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# 6

## Control of Synchronous Generators in Power Systems

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### 6.1 Introduction

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Satisfactory alternating current (AC) power system operation is obtained when frequency and voltage remain nearly constant or vary in a limited and controlled manner when active and reactive loads vary.

Active power flow is related to a prime mover's energy input and, thus, to the speed of the synchronous generator (SG). On the other hand, reactive power control is related to terminal voltage. Too large an electric active power load would lead to speed collapse, while too large a reactive power load would cause voltage collapse.

When a generator acts alone on a load, or it is by far the strongest in an area of a power system, its frequency may be controlled via generator speed, to remain constant with load (isochronous control). On the contrary, when the SG is part of a large power system, and electric generation is shared by two or more SGs, the frequency (speed) cannot be controlled to remain constant because it would forbid generation sharing between various SGs. Control with speed droop is the solution that allows for fair generation sharing.

Automatic generation control (AGC) distributes the generation task between SGs and, based on this as input, the speed control system of each SG controls its speed (frequency) with an adequate speed droop so that generation “desired” sharing is obtained.

By fair sharing, we mean either power delivery proportional to ratings of various SGs or based on some cost function optimization, such as minimum cost of energy.

Speed (frequency) control quality depends on the speed control of the SG and on the other “induced” influences, besides the load dependence on frequency. In addition, torsional shaft oscillations — due to turbine shaft, couplings, generator shaft elasticity, and damping effects — and subsynchronous resonance (due to transmission lines series capacitor compensation to increase transmission power capacity at long distance) influence the quality of speed (active power) control. Measures to counteract such effects are required. Some are presented in this chapter.

In principle, the reactive power flow of an SG may be controlled through SG output voltage control, which, in turn, is performed through excitation (current or voltage) control. SG voltage control quality depends on the SG parameters, excitation power source dynamics with its ceiling voltage, available to “force” the excitation current when needed in order to obtain fast voltage recovery upon severe reactive power load variations. The knowledge of load reactive power dependence on voltage is essential to voltage control system design.

Though active and reactive power control interactions are small in principle, they may influence each other’s control stability. To decouple them, power system stabilizers (PSSs) can be added to the automatic voltage regulators (AVRs). PSSs have inputs such as speed or active power deviations and have lately generated extraordinary interest. In addition, various limiters — such as overexcitation (OEL) and underexcitation (UEL) — are required to ensure stability and avoid overheating of the SG. Load shedding and generator tripping are also included to match power demand to offer.

In a phase of the utmost complexity of SG control, with power quality as a paramount objective, SG models, speed governor models (Chapter 3), excitation systems and their control models, and PSSs, were standardized through Institute of Electrical and Electronics Engineers (IEEE) recommendations.

The development of powerful digital signal processing (DSP) systems and of advanced power electronics converters with insulated gate bipolar transistors (IGBTs), gate turn-off thyristors (GTOs), MOS controlled thyristors (MCTs), together with new nonlinear control systems such as variable structure systems, fuzzy logic neural networks, and self-learning systems, may lead in the near future to the integration of active and reactive power control into unique digital multi-input self-learning control systems. The few attempts made along this path so far are very encouraging.

In what follows, the basics of speed and voltage control are given, while ample reference to the newest solutions is made, with some sample results. For more on power system stability and control see the literature [1–3].

We distinguish in Figure 6.1 the following components:

- Automatic generation control (AGC)
- Automatic reactive power control (AQC)
- Speed/power and the voltage/reactive power droop curves
- Speed governor (Chapter 3) and the excitation system
- Prime mover/turbine (Chapter 3) and SG (Chapter 5)
- Speed, voltage, and current sensors
- Step-up transformer, transmission line ( $X_T$ ), and the power system electromagnetic field (emf),  $E_s$
- PSS added to the voltage controller input

In the basic SG control system, the active and reactive power control subsystems are independent, with only the PSS as a “weak link” between them.

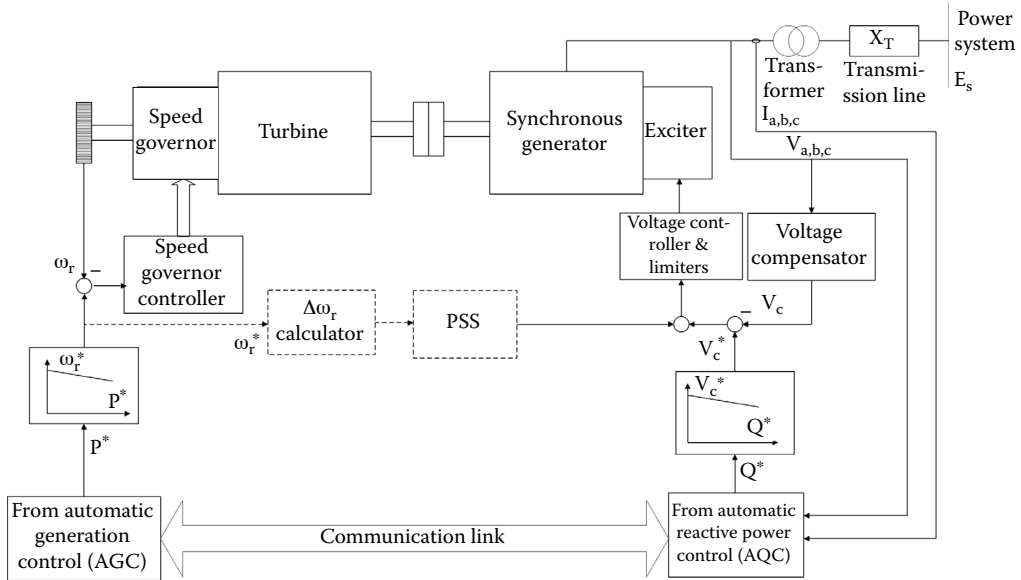


FIGURE 6.1 Generic synchronous generator control system.

The active power reference  $P^*$  is obtained through AGC. A speed (frequency)/power curve (straight line) leads to the speed reference  $\omega_r^*$ . The speed error  $\omega_r^* - \omega_r$  then enters a speed governor control system with output that drives the valves and, respectively, the gates of various types of turbine speed-governor servomotors. AGC is part of the load-frequency control of the power system of which the SG belongs. In the so-called supplementary control, AGC moves the  $\omega_r/P$  curves for desired load sharing between generators. On the other hand, AQC may provide the reactive power reference of the respective generator  $Q^* \neq 0$ .

A voltage/reactive power curve (straight line) will lead to voltage reference  $V_c^*$ . The measured voltage  $V_G$  is augmented by an impedance voltage drop  $I_G(R_G + jX_G)$  to obtain the compensated voltage  $V_c$ . The voltage error  $V_c^* - V_c$  enters the excitation voltage control (AVR) to control the excitation voltage  $V_f$  in such a manner that the reference voltage  $V_c^*$  is dynamically maintained.

The PSS adds to the input of AVR a signal that is meant to provide a positive damping effect of AVR upon the speed (active power) low-frequency local pulsations.

The speed governor controller (SGC), the AVR, and the PSS may be implemented in various ways from proportional integral (PI), proportional integral derivative (PID) to variable structure, fuzzy logic, artificial neural networks (ANNs),  $\mu_{\infty}$ , and so forth. There are also various built-in limiters and protection measures.

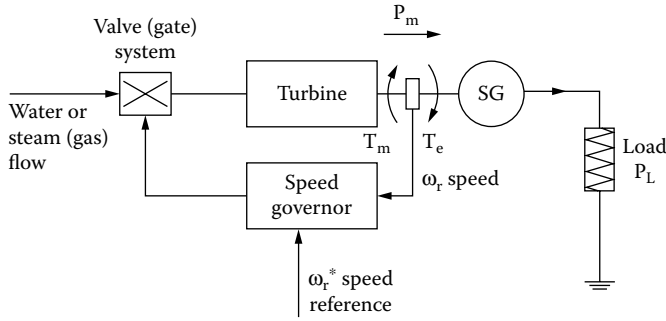
In order to design SGC, AVR, PSS, proper turbine, speed governor, and SG simplified models are required. As for large SGs in power systems, the speed and excitation voltage control takes place within a bandwidth of only 3 Hz, and simplified models are feasible.

## 6.2 Speed Governing Basics

Speed governing is dedicated to generator response to load changes. An isolated SG with a rigid shaft system and its load are considered to illustrate the speed governing concept (Figure 6.2, [1,2]).

The motion equation is as follows:

$$2H \frac{d\omega_r}{dt} = T_m - T_e \quad (6.1)$$



**FIGURE 6.2** Synchronous generator with its own load.

where

$T_m$  = the turbine torque (per unit [P.U.])

$T_e$  = the SG torque (P.U.)

$H$  (seconds) = inertia

We may use powers instead of torques in the equation of motion. For small deviations,

$$\begin{aligned} P &= \omega_r T = P_0 + \Delta P \\ T_m &= T_{m0} + \Delta T_m; T_e = T_{e0} + \Delta T_e \\ \omega_r &= \omega_0 + \Delta \omega_r \end{aligned} \quad (6.2)$$

For steady state,  $T_{m0} = T_{e0}$ ; thus, from Equation 6.1 and Equation 6.2,

$$\Delta P_m - \Delta P_e = \omega_0 (\Delta T_m - \Delta T_e) \quad (6.3)$$

For rated speed  $\omega_0 = 1$  (P.U.),

$$2H \frac{d\Delta \omega_r}{dt} = (\Delta P_m - \Delta P_e) / \omega_0; M = 2H\omega_0 \quad (6.4)$$

The transfer function in Equation 6.4 is illustrated in Figure 6.3.

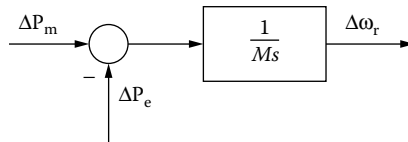
The electromagnetic power  $P_e$  is delivered to composite loads. Some loads are frequency independent (lighting and heating loads). In contrast, motor loads depend notably on frequency. Consequently,

$$\Delta P_e = \Delta P_L + D\Delta \omega_r \quad (6.5)$$

where

$\Delta P_L$  = the load power change, which is independent of frequency

$D$  = a load damping constant



**FIGURE 6.3** Power/speed transfer function (in per unit [P.U.] terms).

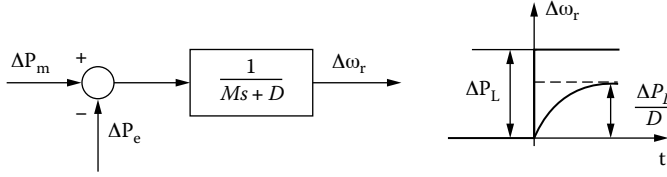


FIGURE 6.4 Power/speed transfer function with load frequency dependence.

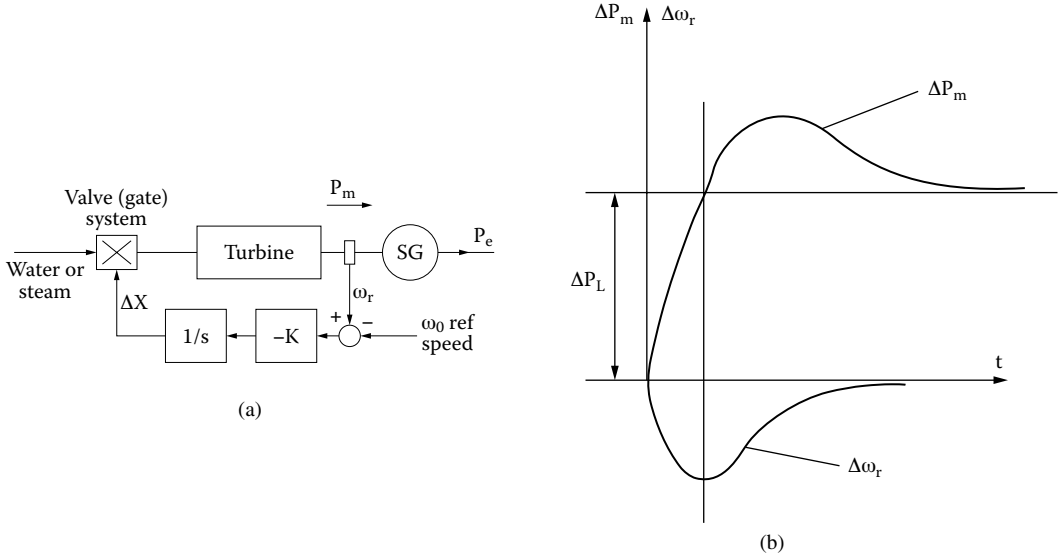


FIGURE 6.5 Isochronous (integral) speed governor: (a) schematics and (b) response to step load increase.

Introducing Equation 6.5 into Equation 6.4 leads to the following:

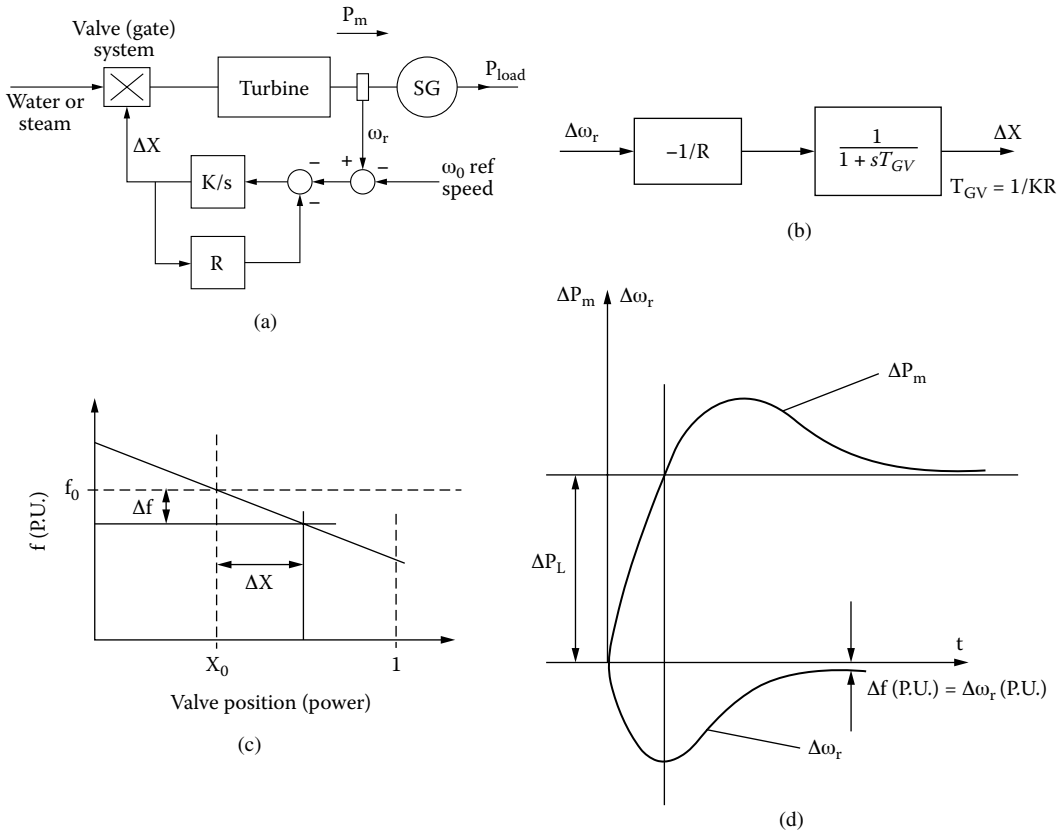
$$2H\omega_0 d \frac{\Delta\omega_r}{dt} + D\Delta\omega_r = \Delta P_m - \Delta P_L \quad (6.6)$$

The new speed/mechanical power transfer function is as shown in Figure 6.4. The steady-state speed deviation  $\Delta\omega_r$ , when the load varies, depends on the load frequency sensitivity. For a step variation in load power ( $\Delta P_L$ ), the final speed deviation is  $\Delta\omega_r = \Delta P_L/D$  (Figure 6.4). The simplest (primitive) speed governor would be an integrator of speed error that will drive the speed to its reference value in the presence of load torque variations. This is called the isochronous speed governor (Figure 6.5a and Figure 6.5b).

The primitive (isochronous) speed governor cannot be used when more SGs are connected to a power system because it will not allow for load sharing. Speed droop or speed regulation is required: in principle, a steady-state feedback loop in parallel with the integrator (Figure 6.6a and Figure 6.6b) will do. It is basically a proportional speed controller with  $R$  providing the steady-state speed vs. load power (Figure 6.6c) straight-line dependence:

$$R = \frac{-\Delta f}{\Delta P_L} \quad (6.7)$$

The time response of a primitive speed-droop governor to a step load increase is characterized now by speed steady-state deviation (Figure 6.6d).



**FIGURE 6.6** The primitive speed-droop governor: (a) schematics, (b) reduced structural diagram, (c) frequency/power droop, and (d) response to step load power.

With two (or more) generators in parallel, the frequency will be the same for all of them and, thus, the load sharing depends on their speed-droop characteristics (Figure 6.7). As

$$\begin{aligned} -\Delta P_1 R_1 &= \Delta f; \\ -\Delta P_2 R_2 &= \Delta f \end{aligned} \tag{6.8}$$

it follows that

$$\frac{\Delta P_2}{\Delta P_1} = \frac{R_1}{R_2} \tag{6.9}$$

Only if the speed droop is the same ( $R_1 = R_2$ ) are the two SGs loaded proportionally to their rating. The speed/load characteristic may be moved up and down by the load reference set point (Figure 6.8).

By moving the straight line up and down, the power delivered by the SG for a given frequency goes up and down (Figure 6.9). The example in Figure 6.9 is related to a 50 Hz power system. It is similar for 60 Hz power systems. In essence, the same SG may deliver at 50 Hz, zero power (point A), 50% power (point B), and 100% power (point C). In strong power systems, the load reference signal changes the power output and not its speed, as the latter is determined by the strong power system.

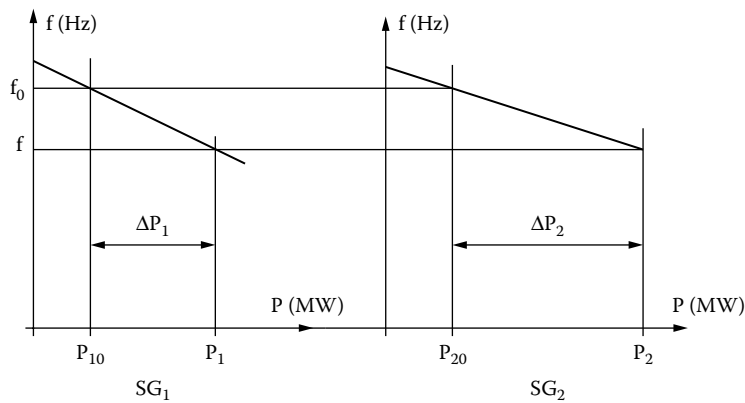


FIGURE 6.7 Load sharing between two synchronous generators with speed-droop governor.

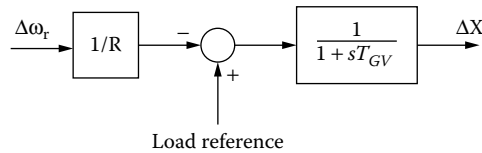


FIGURE 6.8 Speed-droop governor with load reference control.

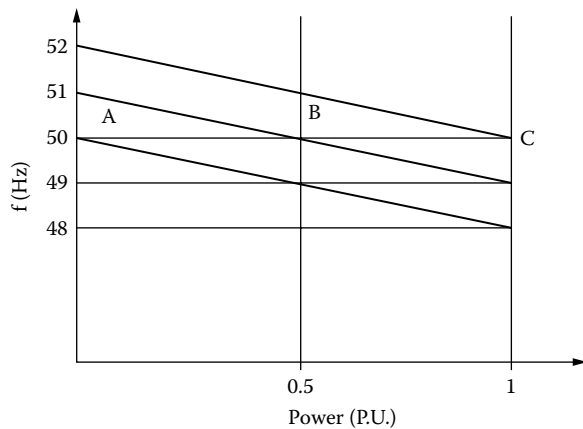


FIGURE 6.9 Moving the frequency (speed)/power characteristics up and down.

It should also be noted that, in reality, the frequency (speed) power characteristics depart from a straight line but still have negative slopes, for stability reasons. This departure is due to valve (gate) nonlinear characteristics; when the latter are linearized, the straight line  $f(P)$  is restored.

### 6.3 Time Response of Speed Governors

In Chapter 3, we introduced models that are typical for steam reheat or nonreheat turbines (Figure 3.9 and Figure 3.10) and hydraulic turbines (Figure 3.40 and Equation 3.42). Here we add them to the speed-droop primitive governor with load reference, as discussed in the previous paragraph (Figure 6.10a and Figure 6.10b):



- $T_{CH}$  is the inlet and steam chest delay (typically: 0.3 sec)
- $T_{RH}$  is the reheater delay (typically: 6 sec)
- $F_{HP}$  is the high pressure (HP) flow fraction (typically:  $F_{HP} = 0.3$ )

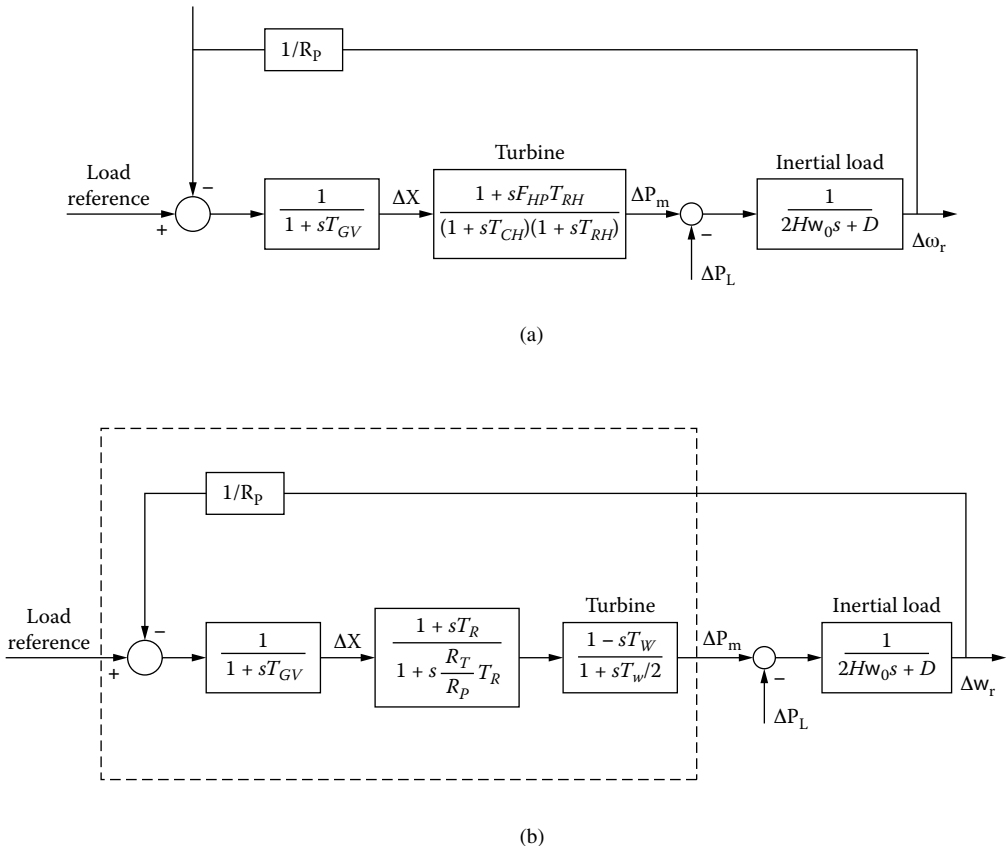
With nonreheater steam turbines:  $T_{RH} = 0$ .

For hydraulic turbines, the speed governor has to contain transient droop compensation. This is so because a change in the position of the gate, at the foot of the penstock, first produces a short-term turbine power change opposite to the expected one. For stable frequency response, long resetting times are required in stand-alone operation.

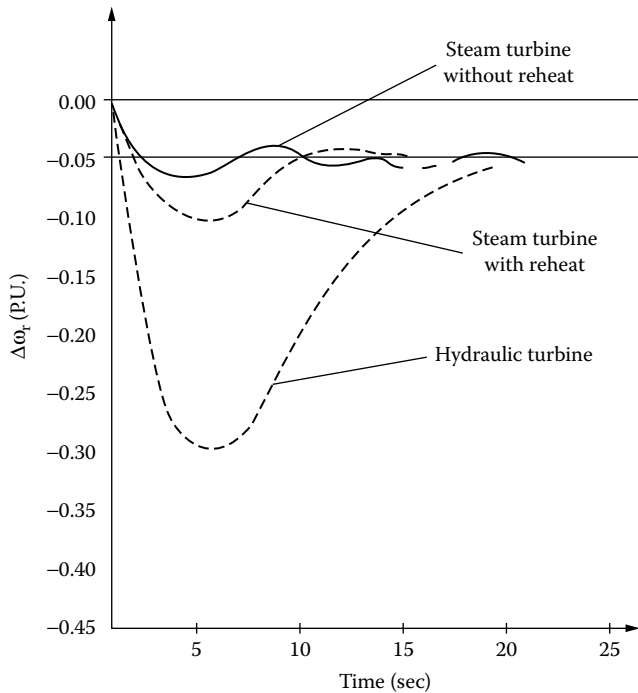
A typical such system is shown in Figure 6.10b:

- $T_W$  is the water starting constant (typically:  $T_W = 1$  sec)
- $R_p$  is the steady-state speed droop (typically: 0.05)
- $T_{GV}$  is the main gate servomotor time constant (typically: 0.2 sec)
- $T_R$  is the reset time (typically: 5 sec)
- $R_T$  is the transient speed droop (typically: 0.4)
- $D$  is the load damping coefficient (typically:  $D = 2$ )

Typical responses of the systems in Figure 6.10a and Figure 6.10b to a step load ( $\Delta P_L$ ) increase are shown in Figure 6.11 for speed deviation  $\Delta\omega_r$  (in P.U.). As expected, the speed deviation response is rather slow for hydraulic turbines, average with reheat steam turbine generators, and rather fast (but oscillatory) for nonreheat steam turbine generators.



**FIGURE 6.10** (a) Basic speed governor and steam turbine generator; (b) basic speed governor and hydraulic turbine generator.



**FIGURE 6.11** Speed deviation response of basic speed governor–turbine–generator systems to step load power change.

The speed governor turbine models in Figure 6.10 are standard. More complete (nonlinear) models are closer to reality. Also, nonlinear, more robust speed governor controllers are to be used to improve speed (or power angle) deviation response to various load perturbations ( $\Delta P_L$ ).

## 6.4 Automatic Generation Control (AGC)

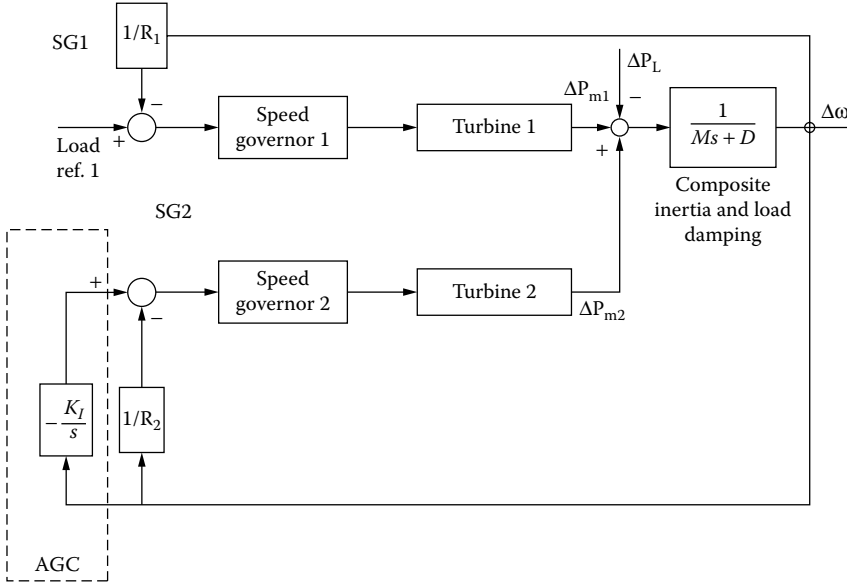
In a power system, when load changes, all SGs contribute to the change in power generation. The restoration of power system frequency requires additional control action that adjusts the load reference set points. Load reference set point modification leads to automatic change of power delivered by each generator.

AGC has three main tasks:

- Regulate frequency to a specified value
- Maintain inter-tie power (exchange between control areas) at scheduled values
- Distribute the required change in power generation among SGs such that the operating costs are minimized

The first two tasks are also called load-frequency control.

In an isolated power system, the function of AGC is to restore frequency, as inter-tie power exchange is not present. This function is performed by adding an integral control on the load reference settings of the speed governors for the SGs with AGC. This way, the steady-state frequency error becomes zero. This integral action is slow and thus overrides the effects of the composite frequency regulation characteristics of the isolated power system (made of all SGs in parallel). Thus, the generation share of SGs that are not under the AGC is restored to scheduled values (Figure 6.12). For an interconnected power system, AGC is accomplished through the so-called tie-line control. And, each subsystem (area) has its own



**FIGURE 6.12** Automatic generation control of one synchronous generator in a two-synchronous-generator isolated power system.

central regulator (Figure 6.13a). The interconnected power system in Figure 6.13 is in equilibrium if, for each area,

$$P_{Gen} = P_{load} + P_{tie} \quad (6.10)$$

The inter-tie power exchange reference  $(P_{tie})_{ref}$  is set at a higher level of power system control, based on economical and safety reasons.

The central subsystem (area) regulator has to maintain frequency at  $f_{ref}$  and the net tie-line power (tie-line control) from the subsystem area at a scheduled value  $P_{tieref}$ . In fact (Figure 6.13b), the tie-line control changes the power output of the turbines by varying the load reference  $(P_{ref})$  in their speed governor systems. The area control error (ACE) is as follows (Figure 6.13b):

$$ACE = -\Delta P_{tie} - \lambda_R \Delta f \quad (6.11)$$

ACE is aggregated from tie-line power error and frequency error. The frequency error component is amplified by the so-called frequency bias factor  $\lambda_R$ . The frequency bias factor is not easy to adopt, as the power unbalance is not entirely represented by load changes in power demand, but in the tie-line power exchange as well.

A PI controller is applied on ACE to secure zero steady-state error. Other nonlinear (robust) regulators may be used. The regulator output signal is  $\Delta P_{ref}$ , which is distributed over participating generators with participating factors  $\alpha_1, \dots, \alpha_n$ . Some participating factors may be zero. The control signal acts upon load reference settings (Figure 6.12).

Inter-tie power exchange and participation factors are allocated based on security assessment and economic dispatch via a central computer.

AGC may be treated as a multilevel control system (Figure 6.14). The primary control level is represented by the speed governors, with their load reference points. Frequency and tie-line control represent secondary control that forces the primary control to bring to zero the frequency and tie-line power deviations.

Economic dispatch with security assessment represents the tertiary control. Tertiary control is the slowest (minutes) of all control stages, as expected.

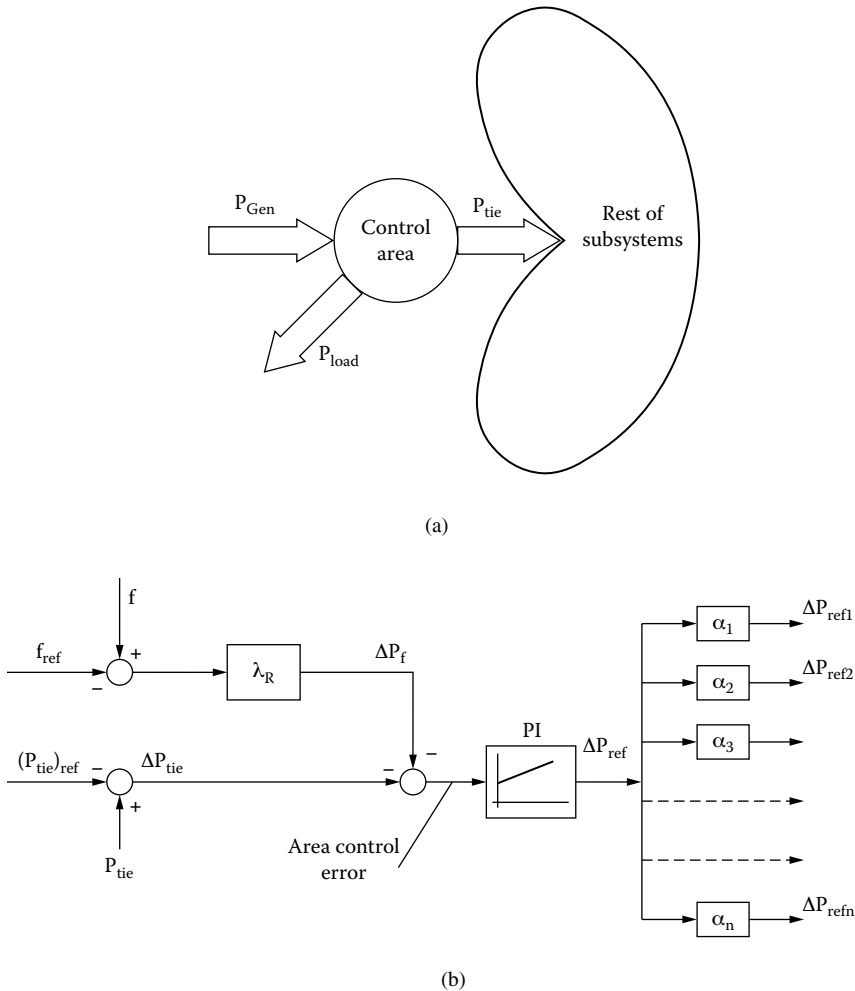


FIGURE 6.13 Central subsystem (tie-line): (a) power balance and (b) structural diagram.

## 6.5 Time Response of Speed (Frequency) and Power Angle

So far, we described the AGC as containing three control levels in an interconnected power system. Based on this, the response in frequency, power angle, and power of a power system to a power imbalance situation may be approached. If a quantitative investigation is necessary, all the components have to be introduced with their mathematical models. But, if a qualitative analysis is sought, then the automatic voltage regulators are supposed to maintain constant voltage, while electromagnetic transients are neglected. Basically, the power system moves from a steady state to another steady-state regime, while the equation of motion applies to provide the response in speed and power angle.

Power system disturbances are numerous, but consumer load variation and disconnection or connection of an SG from (or to) the power system are representative examples. Four time stages in the response to a power system imbalance may be distinguished:

- Rotor swings in the SGs (the first few seconds)
- Frequency drops (several seconds)
- Primary control by speed governors (several seconds)
- Secondary control by central subsystem (area) regulators (up to one minute)

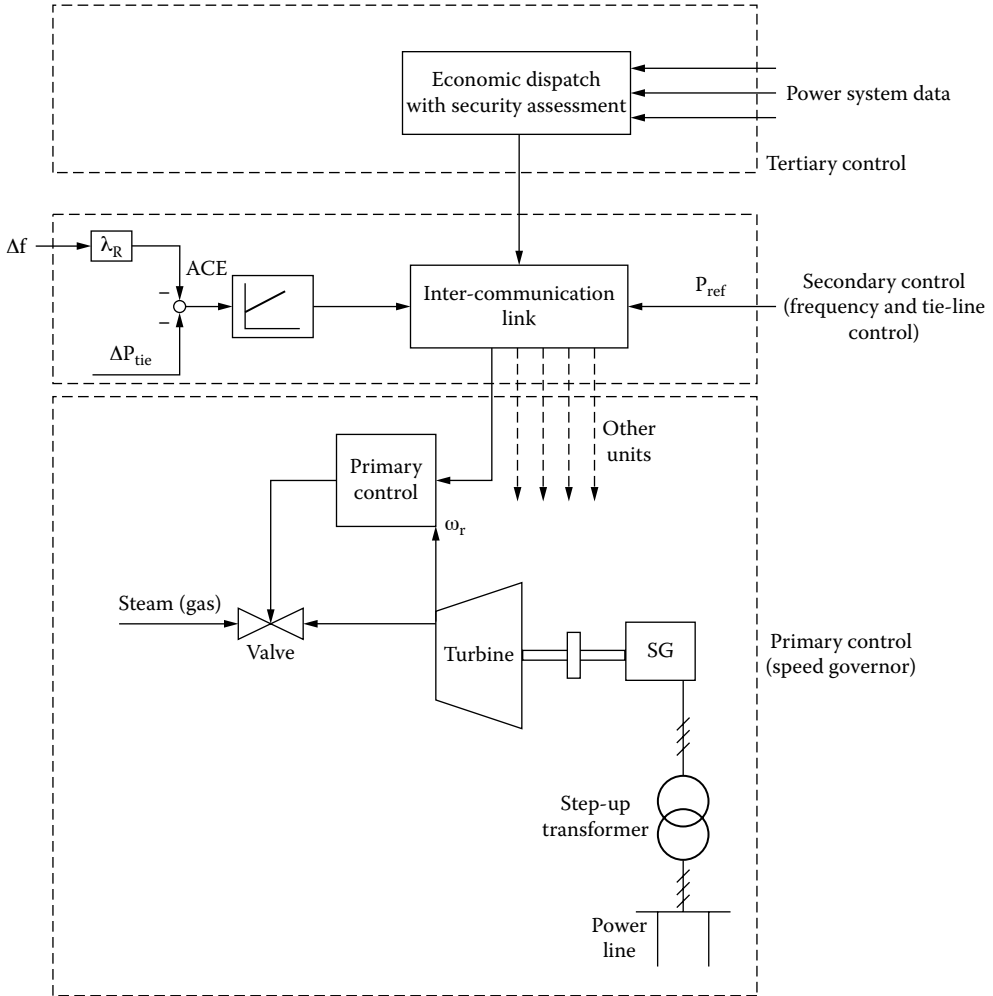


FIGURE 6.14 Automatic generation control as a multilevel control system.

During periodic rotor swings, the mechanical power of the remaining SGs may be considered constant. So, if one generator, out of two, is shut off, the power system mechanical power is reduced twice. The capacity of the remaining generators to deliver power to loads is reduced from the following:

$$P_-(\delta'_0) = \frac{E'V_s}{\frac{X'_d + X_T}{2} + X_s} \sin \delta'_0 \quad (6.12)$$

to

$$P_+(\delta) = \frac{E'V_s \sin \delta'_0}{X'_d + X_T + X_s}, (P.U.) \quad (6.13)$$

in the first moments after one generator is disconnected. Notice that  $X_T$  is the transmission line reactance (there are two lines in parallel) and  $X_s$  is the power system reactance.  $X'_d$  is the transient reactance of the

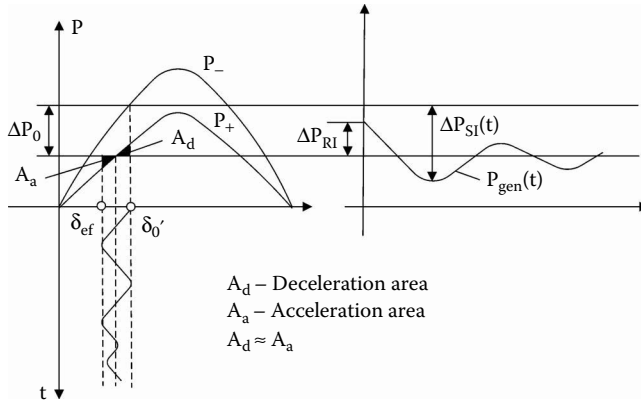


FIGURE 6.15 Rotor swings and power system contributing power change.

generator,  $E'$  is the generator transient emf, and  $V_s$  is the power system voltage. The situation is illustrated in Figure 6.15.

Notice that the load power has not been changed. Both the remaining generator ( $\Delta P_{RI}$ ) and the power system have to cover for the deficit  $\Delta P_0$ :

$$\begin{aligned}\Delta P_{RI} &= P_+(\delta') - P_{m+} \\ \Delta P_{SI} &= \Delta P_0 - \Delta P_{RI}\end{aligned}\quad (6.14)$$

While the motion equation leads to the rotor swings in Figure 6.15, the power system still has to cover for the power  $\Delta P_{SI}(t)$ . So, the transient response to the power system imbalance (by disconnecting a generator out of two) continues with stage two: frequency control.

Due to the additional power system contribution requirement during this second stage, the generators in the power system slow, and the system frequency drops. During this stage, the share from  $\Delta P_{SI}$  is determined by the inertia of the generator. The basic element is that the power angle of the studied generator goes further down while the SG is still in synchronism. When this drop in power angle and frequency occurs, we enter stage three, when primary (speed governors) control takes action, based on the frequency/power characteristics.

The increase in mechanical power required from each turbine is, as known, inversely proportional to the droop in the  $f(P)$  curve (straight line). When the disconnection of one of the two generators occurred, the  $f(P)$  composite curve is changing from  $P_{T-}$  to  $P_{T+}$  (Figure 6.16).

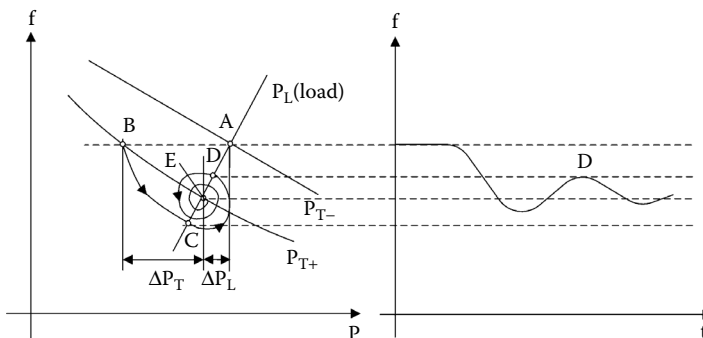


FIGURE 6.16 Frequency response for power imbalance.

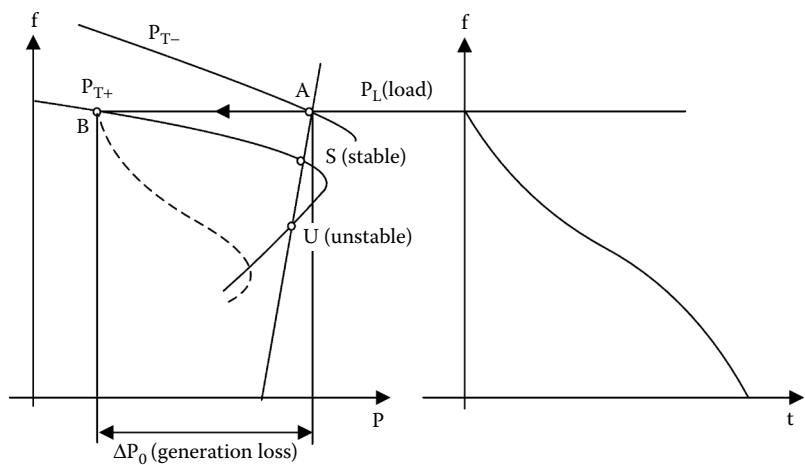


FIGURE 6.17 Extended  $f(P)$  curves with frequency collapse when large power imbalance occurs.

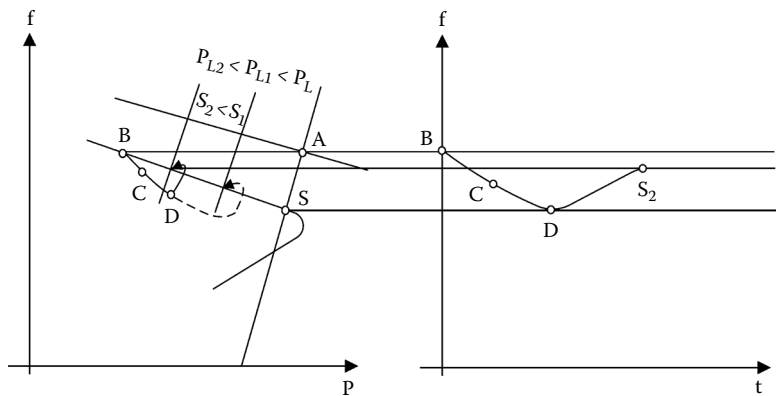


FIGURE 6.18 Frequency restoration via two-stage load shedding.

The operating point moves from A to B as one generator was shut off. The load/frequency characteristic is  $f(P_L)$  in Figure 6.16. Along the trajectory BC, the SG decelerates until it hits the load curve in C, then accelerates up to D and so on, until it reaches the new stable point E.

The straight-line characteristics  $f(P)$  will remain valid — power increases with frequency (speed) reduction — up to a certain power when frequency collapses. In general, if enough power (spinning) reserve exists in the system, the straight-line characteristic holds. Spinning reserve is the difference between rated power and load power in the system. Frequency collapse is illustrated in Figure 6.17.

Because of the small spinning reserve, the frequency decreases initially so much that it intercepts the load curve in U, an unstable equilibrium point. So, the frequency decreases steadily and finally collapses. To prevent frequency collapsing, load shedding is performed. At a given frequency level, underfrequency relays in substations shut down scheduled loads in two to three steps in an attempt to restore frequency (Figure 6.18).

When frequency reaches point C, the first stage of load ( $P_{L1}$ ) shedding is operated. The frequency still decreases, but at a slower rate until it reaches level D, when the second load shedding is performed. This time (as D is at the right side of  $S_2$ ), the generator accelerates and restores frequency at  $S_2$ .

In the last stage of response dynamics, frequency and the tie-line power flow control through the AGC take action. In an islanded system, AGC actually moves up stepwise the  $f(P)$  characteristics of generators

such as to restore frequency to its initial value. Details on frequency dynamics in interconnected power systems can be found in the literature [1, 2].

## 6.6 Voltage and Reactive Power Control Basics

Dynamically maintaining constant (or controlled) voltage in a power system is a fundamental requirement of power quality. Passive (resistive-inductive, resistive-capacitive) loads and active loads (motors) require both active and reactive power flows in the power system.

While composite load power dependence on frequency is mild, the reactive load power dependency on voltage is very important. Typical shapes of composite load (active and reactive power) dependence on voltage are shown in Figure 6.19.

As loads “require” reactive power, the power system has to provide for it. In essence, reactive power may be provided or absorbed by the following:

- Control of excitation voltage of SGs by automatic voltage regulation (AVR)
- Power-electronics-controlled capacitors and inductors by static voltage controllers (SVCs) placed at various locations in a power system

As voltage control is related to reactive power balance in a power system, to reduce losses due to increased power-line currents, it is appropriate to “produce” the reactive power as close as possible to the place of its “utilization.” Decentralized voltage (reactive power) control should thus be favored.

As the voltage variation changes, both the active and reactive power that can be transmitted over a power network vary, and it follows that voltage control interferes with active power (speed) control. The separate treatment of voltage and speed control is based on their weak coupling and on necessity. One way to treat this coupling is to add to the AVR the so-called PSS, with input that is speed or active power deviation.

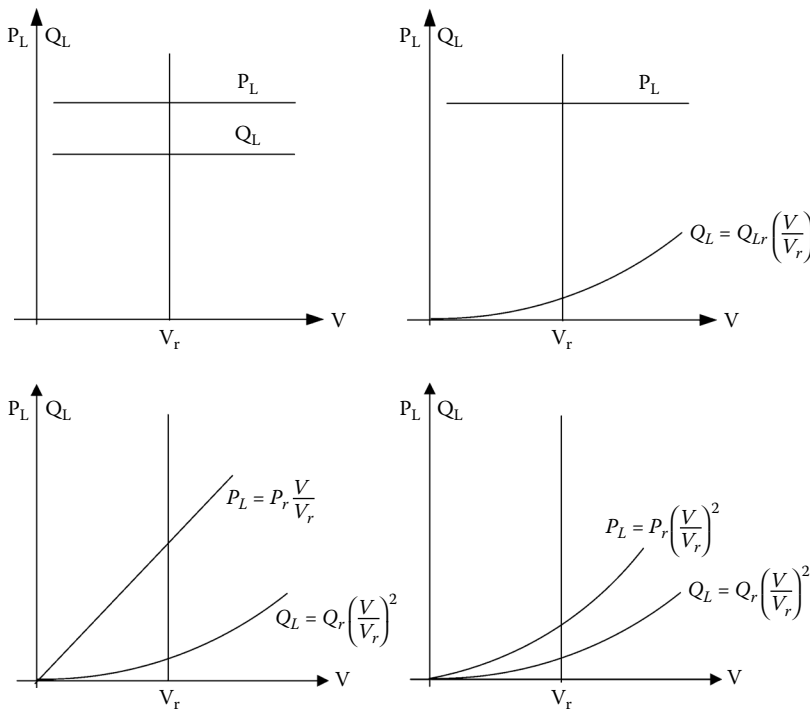


FIGURE 6.19 Typical  $P_L$ ,  $Q_L$  load powers vs. voltage.



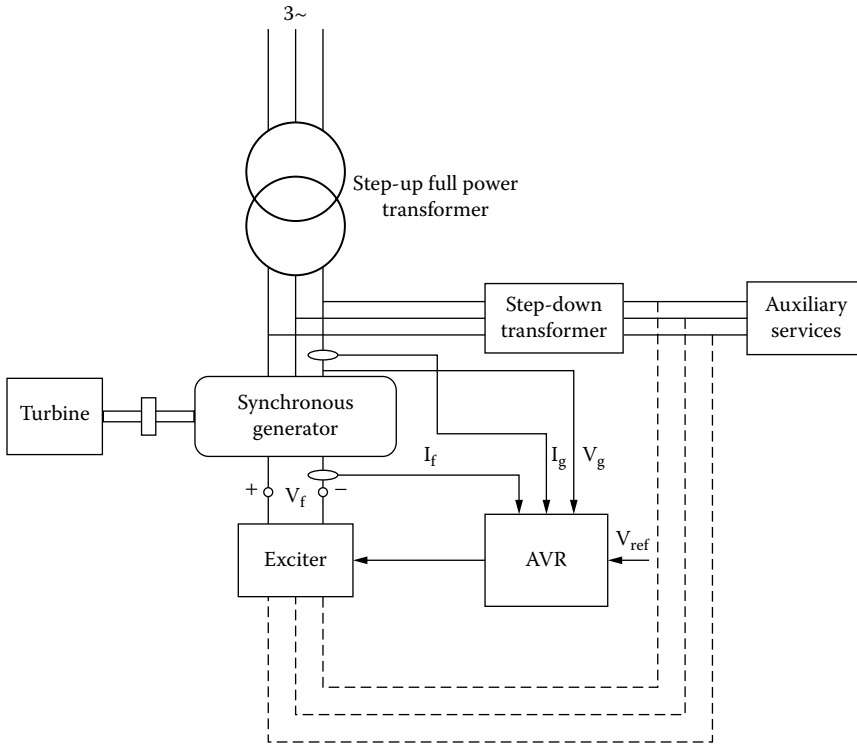


FIGURE 6.20 Exciter with automatic voltage regulator (AVR).

## 6.7 The Automatic Voltage Regulation (AVR) Concept

AVR acts upon the DC voltage  $V_f$  that supplies the excitation winding of SGs. The variation of field current in the SG increases or decreases the emf (no load voltage); thus, finally, for a given load, the generator voltage is controlled as required. The excitation system of an SG contains the exciter and the AVR (Figure 6.20).

The exciter is, in fact, the power supply that delivers controlled power to SG excitation (field) winding. As such, the exciters may be classified into the following:

- DC exciters
- AC exciters
- Static exciters (power electronics)

The DC and AC exciters contain an electric generator placed on the main (turbine-generator) shaft and have low power electronics control of their excitation current. The static exciters take energy from a separate AC source or from a step-down transformer (Figure 6.20) and convert it into DC-controlled power transmitted to the field winding of the SG through slip-rings and brushes.

The AVR collects information on generator current and voltage ( $V_g$ ,  $I_g$ ) and on field current, and, based on the voltage error, controls the  $V_f$  (the voltage of the field winding) through the control voltage  $V_{con}$ , which acts on the controlled variable in the exciter.

## 6.8 Exciters

As already mentioned, exciters are of three types, each with numerous embodiments in industry.

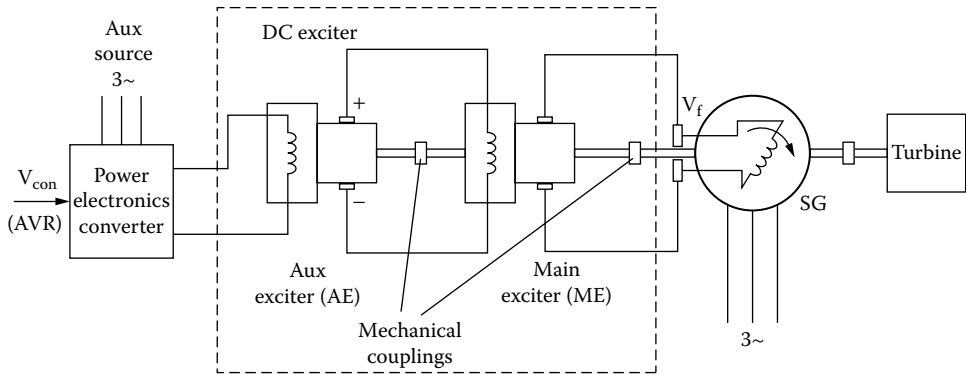


FIGURE 6.21 Typical direct current (DC) exciter.

The DC exciter (Figure 6.21), still in existence for many SGs below 100 MVA per unit, consists of two DC commutator electric generators: the main exciter (ME) and the auxiliary exciter (AE). Both are placed on the SG main shaft. The ME supplies the SG field winding ( $V_f$ ), while the AE supplies the ME field winding.

Only the field winding of the auxiliary exciter is supplied with the voltage  $V_{con}$  controlled by the AVR. The power electronics source required to supply the AE field winding is of very low power ratings, as the two DC commutator generators provide a total power amplification ratio around 600/1.

The advantage of a low power electronics external supply required for the scope is paid for by the following:

- A rather slow time response due to the large field-winding time constants of the two excitation circuits plus the moderate time constants of the two armature windings
- Problems with brush wearing in the ME and AE
- Transmission of all excitation power (the peak value may be 4 to 5% of rated SG power) of the SG has to be through the slip-ring brush mechanism
- Flexibility of the exciter shafts and mechanical couplings adds at least one additional shaft torsional frequency to the turbine-generator shaft

Though still present in industry, DC exciters were gradually replaced with AC exciters and static exciters.

### 6.8.1 AC Exciters

AC exciters basically make use of inside-out synchronous generators with diode rectifiers on their rotors. As both the AC exciter and the SG use the same shaft, the full excitation power diode rectifier is connected directly to the field winding of SG (Figure 6.22). The stator-based field winding of the AC exciter is controlled from the AVR.

The static power converter now has a rating about 1/20(30) of the SG excitation winding power rating, as only one step of power amplification is performed through the AC exciter.

The AC exciter in Figure 6.22 is characterized by the following:

- Absence of electric brushes in the exciter and in the SG
- Addition of a single machine on the main SG-turbine shaft
- Moderate time response in  $V_f$  (SG field-winding voltage), as only one (transient) time constant ( $T_{d0}'$ ) delays the response; the static power converter delay is small in comparison
- Addition of one torsional shaft frequency due to the flexibility of the AC exciter machine shaft and mechanical coupling
- Small controlled power in the static power converter: (1/20[30] of the field-winding power rating)

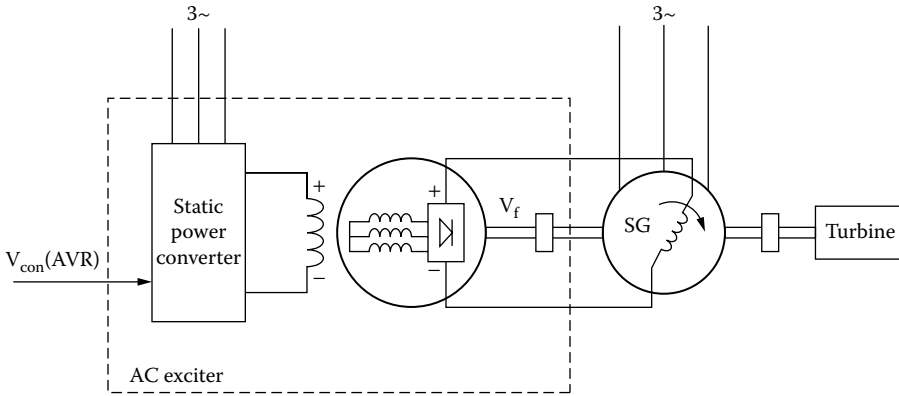


FIGURE 6.22 Alternating current (AC) exciter.

The brushless AC exciter (as in Figure 6.22) is used frequently in industry, even for new SGs, because it does not need an additional sizable power source to supply the exciter's field winding.

## 6.8.2 Static Exciters

Modern electric power plants are provided with emergency power groups for auxiliary services that may be used to start the former from blackout. So, an auxiliary power system is generally available.

This trend gave way to static exciters, mostly in the form of controlled rectifiers directly supplying the field winding of the SG through slip-rings and brushes (Figure 6.23a and Figure 6.23b). The excitation transformer is required to adapt the voltage from the auxiliary power source or from the SG terminals (Figure 6.23a).

It is also feasible to supply the controlled rectifier from a combined voltage transformer (VT) and current transformer (CT) connected in parallel and in series with the SG stator windings (Figure 6.23b). This solution provides a kind of basic AC voltage stabilization at the rectifier input terminals. This way, short-circuits or short voltage sags at SG terminals do not much influence the excitation voltage ceiling produced by the controlled rectifier.

In order to cope with fast SG excitation current control, the latter has to be forced by an overvoltage available to be applied to the field winding. The voltage ceiling ratio ( $V_{fmax}/V_{frated}$ ) characterizes the exciter.

Power electronics (static) exciters are characterized by fast voltage response, but still the  $T_d'$  time constant of the SG delays the field current response. Consequently, a high-voltage ceiling is required for all exciters.

To exploit with minimum losses the static exciters, two separate controlled rectifiers may be used, one for "steady state" and one for field forcing (Figure 6.24). There is a switch that has to be kept open unless the field-forcing (higher voltage) rectifier has to be put to work. When  $V_{fmax}/V_{frated}$  is notably larger than two, such a solution may be considered.

The development of IGBT pulse-width modulator (PWM) converters up to 3 MVA per unit (for electric drives) at low voltages (690 VAC, line voltage) provides for new, efficient, lower-volume static exciters.

The controlled thyristor rectifiers in Figure 6.24 may be replaced by diode rectifiers plus DC–DC IGBT converters (Figure 6.25).

A few such four-quadrant DC–DC converters may be paralleled to fulfill the power level required for the excitation of SGs in the hundreds of MVAs per unit. The transmission of all excitation power through slip-rings and brushes remains a problem. However, with today's doubly fed induction generators at 400 MVA/unit, 30 MVA is transmitted to the rotor through slip-rings and brushes. The solution is, thus, here for the rather lower power ratings of exciters (less than 3 to 4% of SG rating).

The four-quadrant chopper static exciter has the following features:

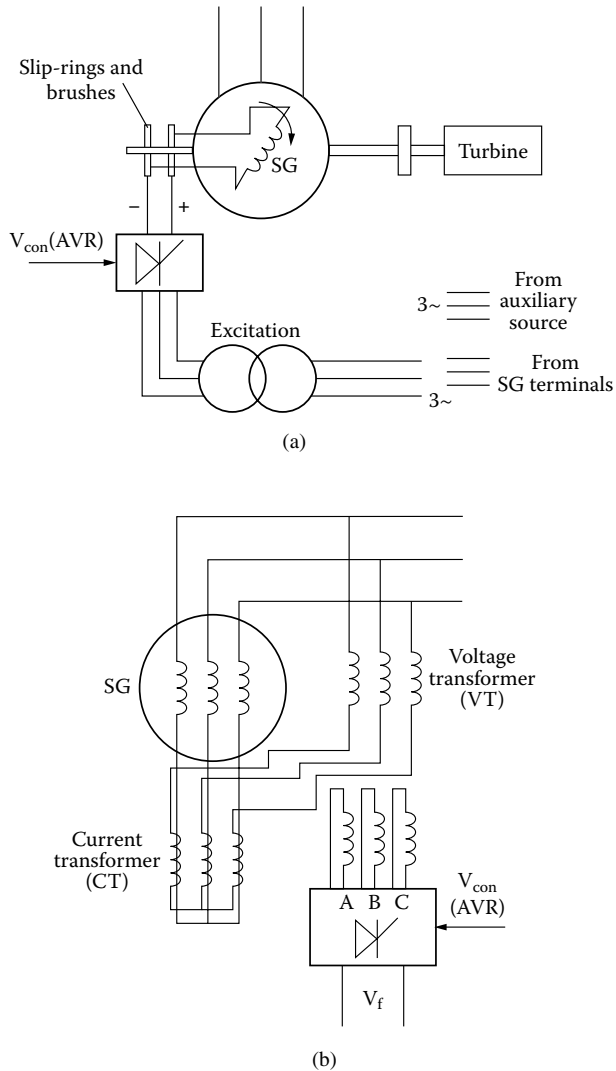


FIGURE 6.23 Static exciter: (a) voltage fed and (b) voltage and current fed.

- It produces fast current response with smaller ripple in the field-winding current of the SG.
- It can handle positive and negative field currents that may occur during transients as a result of stator current transients.
- The AC input currents (in front of the diode rectifier) are almost sinusoidal (with proper filtering), while the power factor is close to unity, irrespective of load (field) current.
- The current response is even faster than that with controlled rectifiers.
- Active front-end IGBT rectifiers may also be used for static exciters.

## 6.9 Exciter's Modeling

While it is possible to derive complete models for exciters — as they are interconnected electric generators or static power converters — for power system stability studies, simplified models have to be used. The IEEE standard 421.5 from 1992 contains “IEEE Recommended Practice for Excitation System Models for Power Systems.”

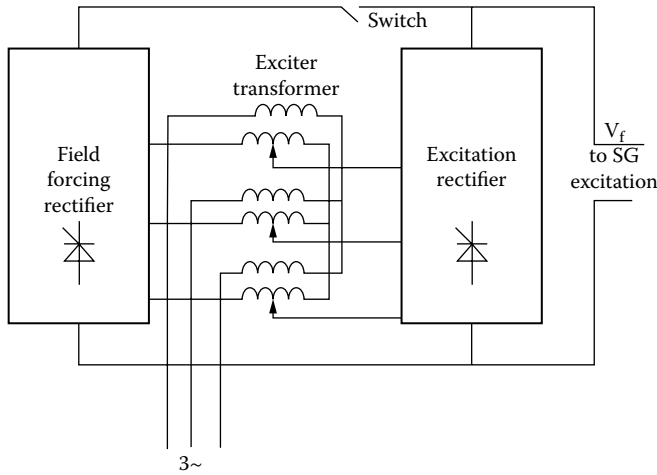


FIGURE 6.24 Dual rectifier static exciter.

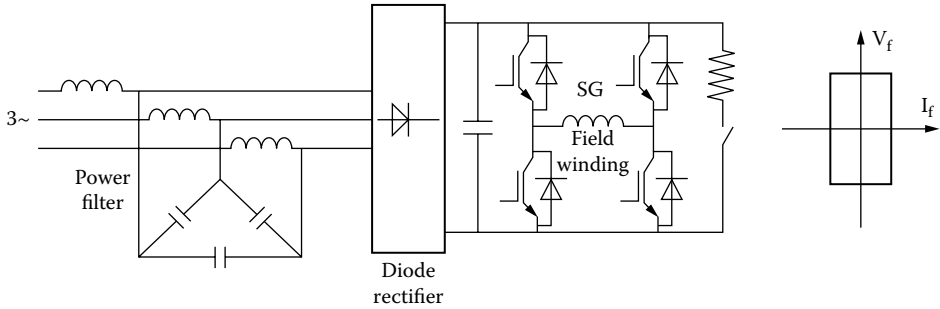


FIGURE 6.25 Diode-rectifier and four-quadrant DC–DC converter as static exciter.

Moreover, “Computer Models for Representation of Digital-Based Excitation Systems” were also recommended by IEEE in 1996.

### 6.9.1 New P.U. System

The so-called reciprocal P.U. system used for the SG, where the base voltage for the field-winding voltage  $V_f$  is the SG terminal rated voltage  $V_n \times \sqrt{2}$  leads to a P.U. value of  $V_f$  in the range of 0.003 or so. Such values are too small to handle in designing the AVR.

A new, nonreciprocal, P.U. system is now widely used to handle this situation. Within this P.U. system, the base voltage for  $V_f$  is  $V_{fb}$ , the field-winding voltage required to produce the airgap line (nonsaturated) no-load voltage at the generator terminals. For the SG in P.U., at no load,

$$\begin{aligned} V_{d0} &= +\Psi_{q0} = +L_q I_{q0} = 0 \\ V_{q0} &= -\Psi_{d0} = -L_{dm} I_f \\ |V_{q0}| &= V_0 = I_{dm} I_f = 1.0 \end{aligned} \tag{6.15}$$

So,

$$I_f = 1/l_{dm}(P.U.) \quad (6.16)$$

The field voltage  $V_f$  corresponding to  $I_f$  is as follows:

$$V_f = r_f \cdot I_f = \frac{r_f}{l_{dm}}(P.U.) \quad (6.17)$$

This is the reciprocal P.U. system.

In the nonreciprocal P.U. system, the corresponding field current  $I_{fb} = 1.0$ ; thus,

$$I_{fb} = l_{dm} I_f \quad (6.18a)$$

The exciter voltage in the new P.U. system is, thus,

$$V_{fb} = \frac{l_{dm}}{r_f} V_f \quad (6.18b)$$

Using Equation 6.16 in Equation 6.18, we evidently find  $V_{fb} = 1.0$ , as we are at no-load conditions (Equation 6.15). In [Chapter 5](#), the operational flux  $\Psi_d$  at no load was defined as follows:

$$\Delta\Psi_d(s) = \frac{l_{dm}}{r_f} \frac{(1+sT_D)\Delta V_f}{(1+sT'_{d0})(1+sT''_{d0})} \quad (6.19)$$

in the reciprocal P.U. system.

In the new, nonreciprocal, P.U. system, by using Equation 6.18 in Equation 6.19, we obtain the following:

$$\Delta\Psi_{db}(s) = \frac{(1+sT_D)\Delta V_{fb}}{(1+sT'_{d0})(1+sT''_{d0})} \quad (6.20)$$

However, at no load,

$$\Delta\Psi_{db} = \Delta V \quad (6.21)$$

Consequently, with the damping winding eliminated ( $T''_{d0}, T_D = 0$ ),

$$\frac{\Delta V_0(s)}{\Delta V_{fb}(s)} = \frac{1}{1+sT'_{d0}} \quad (6.22)$$

The open-circuit transfer function of the generator has a gain equal to unity and the time constant  $T'_{d0}$ :

$$T'_{d0} = \frac{1}{\omega_{base}} \cdot \frac{(l_{fb} + l_{dm})}{r_f} \quad (6.23)$$

**Example 6.1**

Consider an SG with the following P.U. parameters:  $l_{dm} = l_{qm} = 1.6$ ,  $l_{sl} = 0.12$ ,  $l_{fl} = 0.17$ ,  $r_f = 0.0064$ .

The rated voltage  $V_0 = 24/\sqrt{3}$  kV,  $f_1 = 60$  Hz. The field current and voltage required to produce the rated generator voltage at no load on the airgap line are  $I_f = 1500$  A,  $V_f = 100$  V.

Calculate the following:

1. The base values of  $V_f$  and  $I_f$  in the reciprocal and nonreciprocal ( $V_{fb}$ ,  $I_{fb}$ ) P.U. system
2. The open-circuit generator transfer function  $\Delta V_0/\Delta V_{fb}$

*Solution*

1. Evidently,  $V_{fb} = 100$  V,  $I_{fb} = 1500$  A, by definition, in the nonreciprocal P.U. system.

For the reciprocal P.U. system, we make use of Equation 6.17 and Equation 6.18:

$$I_f = l_{dm} I_{fb} = 1.6 \cdot 1500 = 2400 \text{ A}$$

$$V_f = \frac{l_{dm}}{r_f} V_{fb} = \left( \frac{1.6}{0.0064} \right) \cdot 100 = 250 \text{ kV}$$

2. In the absence of damper winding, only the time constant  $T'_{d0}$  remains to be determined (Equation 6.23):

$$T'_{d0} = \frac{1}{2\pi 60} \cdot \frac{(0.17 + 1.6)}{0.0064} = 7.34 \text{ sec}$$

$$\frac{\Delta V_0(s)}{\Delta V_{fb}(s)} = \frac{1}{1 + 7.34 \times s}$$

When temperature varies,  $r_f$  varies, and thus, all base variables vary. The time constant  $T'_{d0}$  also varies.

**6.9.2 The DC Exciter Model**

Consider the separately excited DC commutator generator exciter (Figure 6.7), with its no-load and on-load saturation curves at constant speed.

Due to magnetic saturation, the relationship between DC exciter field current  $I_{ef}$  and the output voltage  $V_{ex}$  is nonlinear (Figure 6.26). The airgap line slope in Figure 6.26 is  $R_g$  (as in a resistance). In the IEEE standard 451.2, the magnetic saturation is defined by the saturation factor  $S_e(V_{ex})$ :

$$I_{ef} = \frac{V_{ex}}{R_g} + \Delta I_{ef} \quad (6.24)$$

$$\Delta I_{ef} = V_{ex} \cdot S_e(V_{ex})$$

The saturation factor is approximated by using an exponential function:

$$S_e(V_{ex}) = \frac{1}{R_g} e^{B_e V_{ex}} \quad (6.25)$$

Other approximations are also feasible.

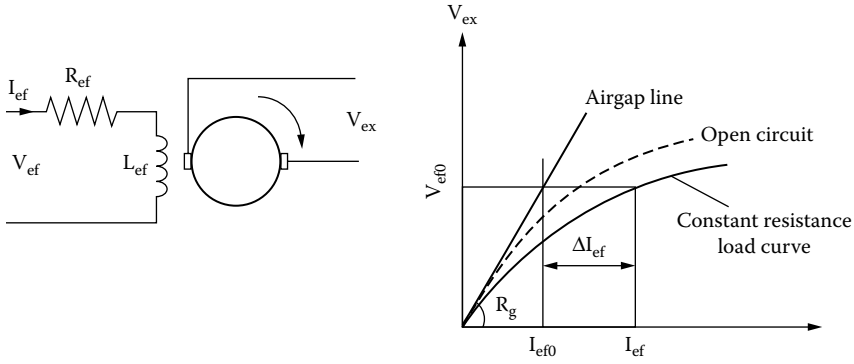


FIGURE 6.26 DC exciter and load-saturation curve.

The no-load DC exciter voltage  $V_{ex}$  is proportional to its excitation field  $\Psi_{ef}$ . For constant speed,

$$V_{ex} = K_e \cdot \Psi_{ef} = K_e \cdot L_{ef} \cdot I_{ef} \quad (6.26)$$

$$V_{ef} = R_{ef} I_{ef} + \frac{d\Psi_{ef}}{dt} = R_{ef} I_{ef} + L_{ef} \frac{dI_{ef}}{dt} \quad (6.27)$$

With Equation 6.24 through Equation 6.26, Equation 6.27 becomes

$$V_{ef} = \left( \frac{R_{ef}}{R_g} + R_{ef} S_e(V_{ex}) \right) V_{ex} + \frac{1}{K_e} \frac{dV_{ex}}{dt} \quad (6.28)$$

This is basically the voltage transfer function of the DC exciter on no load, considering magnetic saturation.

Again, P.U. variables are used with base voltage equal to the SG base field voltage  $V_{fb}$ :

$$V_{exb} = V_{fb} \quad (6.29)$$

$$I_{efb} = V_{fb} / R_g; R_{gb} = R_g$$

In P.U., the saturation factor becomes

$$s_e(V_{ex}) = R_g S_e(V_{ex}) \quad (6.30)$$

Finally, Equation 6.28 in P.U. is as follows:

$$V_{ef} = \frac{R_{ef}}{R_g} V_{ex} (1 + s_e(V_{ex})) + \frac{1}{K_e} \frac{dV_{ex}}{dt} \quad (6.31)$$

It is obvious that  $1/K_e$  has the dimension of a time constant:

$$\frac{1}{K_e} \approx \frac{L_{ef}}{R_g} \frac{I_{ef0}}{V_{ex0}} = \frac{L_{ef}}{R_g} = T_{ex} \quad (6.32)$$



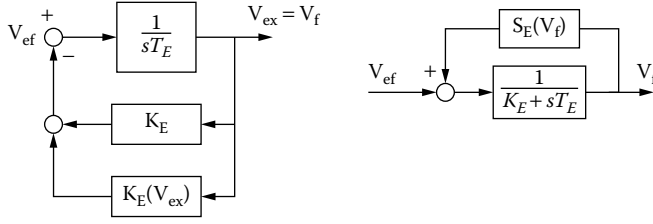


FIGURE 6.27 DC exciter.

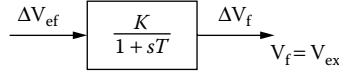


FIGURE 6.28 Small-signal deviation of DC exciters with separate excitation.

The values  $I_{ef0}$  and  $V_{ex0}$  in P.U., now correspond to a given operating point. Finally, Equation 6.31 becomes

$$V_{ef} = V_{ex} \left( K_E + S_E(V_{ex}) \right) + T_E \frac{dV_{ex}}{dt} \quad (6.33)$$

with

$$K_E = \frac{R_{ef}}{R_g}; \quad (6.34)$$

$$S_E(V_{ex}) = s_e(V_{ex}) \cdot \frac{R_{ef}}{R_g}$$

This is the widely accepted DC exciter model used for AVR design and power system stability studies. It may be expressed in a structural diagram as shown in Figure 6.27.

It is evident that for small-signal analysis, the structural diagram in Figure 6.27 may be simplified to the following:

$$\Delta V_{ef} = \Delta V_f \frac{(1 + sT)}{K} \quad (6.35)$$

$$K = \frac{1}{S_E(V_{ef0}) + K_E}; T = KT_E$$

The corresponding structural diagram is shown in Figure 6.28. As expected, in its most simplified form, for small-signal deviations, the DC exciter is represented by a gain and a single time constant. Both  $K$  and  $T$ , however, vary with the operating point ( $V_{f0}$ ). Note that the self-excited DC exciter model is similar, but with  $K_E = R_{ef}/R_g - 1$  instead of  $K_E = R_{ef}/R_g$ . Also,  $K_E$  now varies with the operating point.

### 6.9.3 The AC Exciter

The AC exciter is, in general, a synchronous generator (inside-out for brushless excitation systems). Its control is again through its excitation and, in a way, is similar to the DC exciter. If a diode rectifier is used at the output of the AC exciter, the output DC current  $I_f$  is proportional to the armature current, as almost unity power factor operation takes place with diode rectification. What is additional in the AC

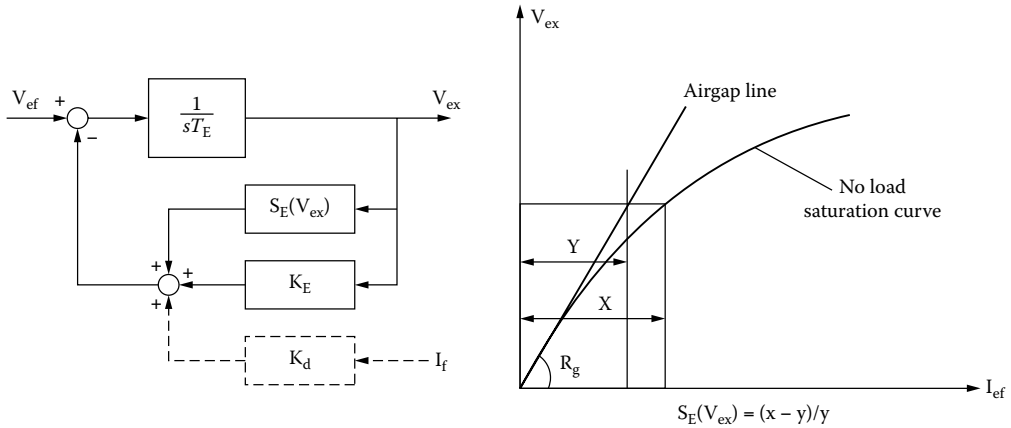


FIGURE 6.29 AC exciter alternator.

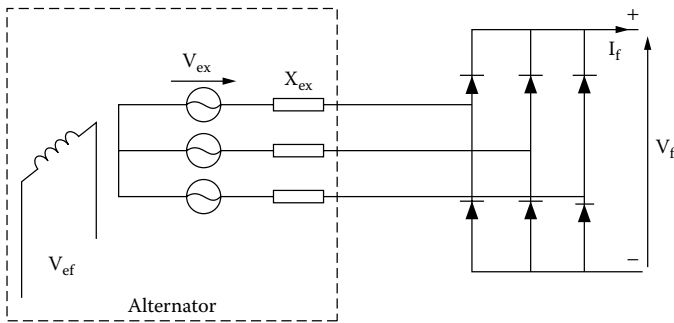


FIGURE 6.30 Diode rectifier plus alternator equals AC exciter.

exciter is a longitudinal demagnetizing armature reaction that tends to reduce the terminal voltage of the AC exciter. Consequently, one more feedback is added to the DC exciter model (Figure 6.29) to obtain the model of the AC exciter.

The saturation factor  $S_E(V_f)$  should now be calculated from the no-load saturation curve and the airgap line of the AC exciter. The armature reaction feedback coefficient  $K_d$  is related to the  $d$  axis coupling inductance of the AC exciter ( $l_{dm}$ , when the field winding of the AC exciter is reduced to its armature winding). It is obvious that the influence of armature resistance and damper cage (if any) are neglected, and speed is considered constant. It is  $V_{ex}$  and not  $V_f$  in Figure 6.29, because a rectifier is used between the AC exciter and the SG field winding to change AC to DC. The uncontrolled rectifier that is part of the AC exciter is shown in Figure 6.30.

The  $V_f(I_f)$  output curve of the diode rectifier is, in general, nonlinear and depends on the diode commutation overlapping. The alternator reactance (inductance)  $x_{ex}$  plays a key role in the commutation process. Three main operation modes may be identified from no load to short-circuit [5]:

- Stage 1: two diodes conducting before commutation takes place (low load):

$$\frac{V_f}{V_{ex}} = 1 - \frac{1}{\sqrt{3}} \frac{I_f}{I_{sc}}, \text{ for } I_f / I_{sc} < (1 - 1/\sqrt{3}) \quad (6.36)$$

$$I_{sc} = \frac{V_{ex} \sqrt{2}}{x_{ex}} \quad (6.37)$$

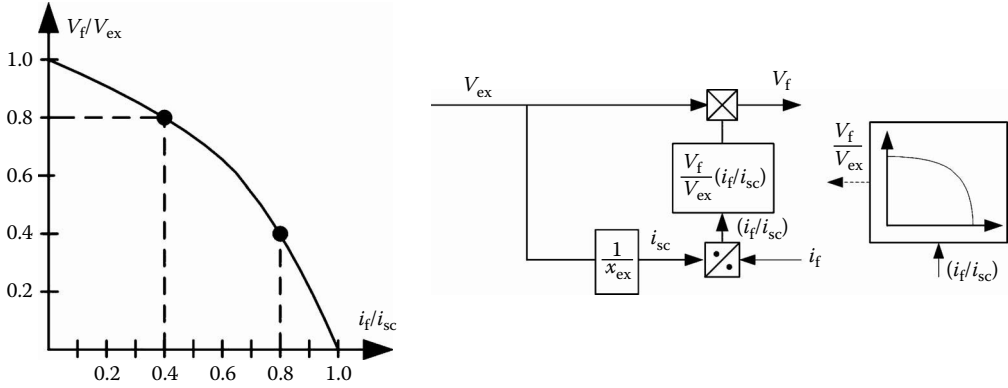


FIGURE 6.31 Diode rectifier voltage/current characteristic and structural diagram.

- Stage 2: when each diode can conduct only when the counterconnected diode of the same phase has ended its conduction interval:

$$\frac{V_f}{V_{ex}} = \sqrt{\frac{3}{4} - \left(\frac{i_f}{i_{sc}}\right)^2}; \quad (6.38)$$

$$1 - 1/\sqrt{3} < \frac{I_f}{I_{sc}} < \frac{3}{4}$$

- Stage 3: four diodes conduct at the same time:

$$\frac{V_f}{V_{ex}} = \sqrt{3} \left(1 - \frac{i_f}{i_{sc}}\right); \quad (6.39)$$

$$\frac{3}{4} < \frac{i_f}{i_{sc}} < 1$$

The  $V_f/V_{ex}(i_f/i_{sc})$  functions in Equation 6.36, Equation 6.38, and Equation 6.39 are illustrated in Figure 6.31. This is a steady-state characteristic. The response of the rectifier is so fast, in comparison with the alternator or to the SG field current response, that the steady-state characteristic suffices to model the rectifier.

## 6.9.4 The Static Exciter

Among the static exciter configurations, let us consider here the controlled three-phase rectifier (Figure 6.32).

The average value (steady-state) characteristic represents the output voltage of the  $V_f$  as a function of input voltage  $V_{ex}$  and the load ( $I_f$ ) current [5, 6]:

$$V_f = \frac{3\sqrt{2}}{\pi} V_{ex} \sqrt{3} \cos \alpha - \frac{3}{\pi} x_{ex} I_f \quad (6.40)$$

$$I_{sc} = \frac{V_{ex} \sqrt{2}}{x_{ex}}$$

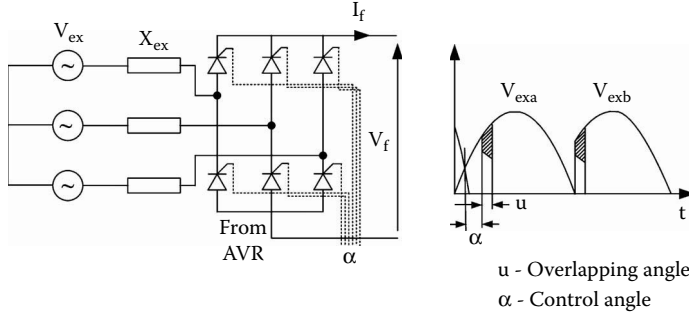


FIGURE 6.32 The controlled rectifier.

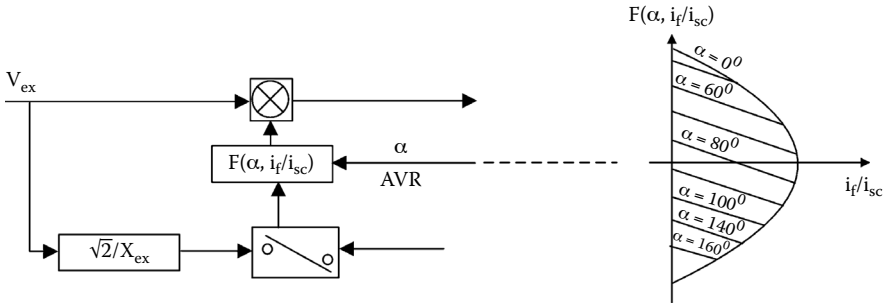


FIGURE 6.33 The structure of a controlled rectifier.

In P.U. values,

$$\frac{V_f}{V_{ex}} = \cos \alpha - \frac{1}{\sqrt{3}} I_f / I_{sc} = F(\alpha, i_f / i_{sc}) \quad (6.41)$$

The characteristic in Equation 6.41 is similar to the first stage of the diode rectifier characteristic. The structural diagram is also similar (Figure 6.33). For  $\alpha = 0$ , it degenerates into stage 1 of the diode rectifier case (Equation 6.36).

This time, the voltage  $V_f$  applied to the field winding may be either positive or negative, while the field current  $I_f$  is always positive. Faster response in  $I_f$  is expected, while the control is done through the firing delay angle  $\alpha$ .

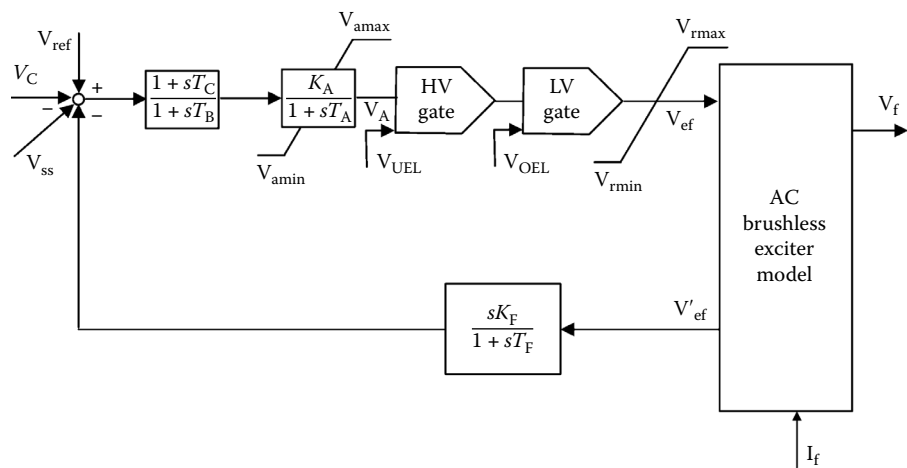
The power source (a transformer in general) has a rather constant emf  $V_{ex}$  and an internal reactance  $x_{ex}$ , so  $\cos \alpha$  is input to the rectifier and is produced as the output of the AVR.

## 6.10 Basic AVRs

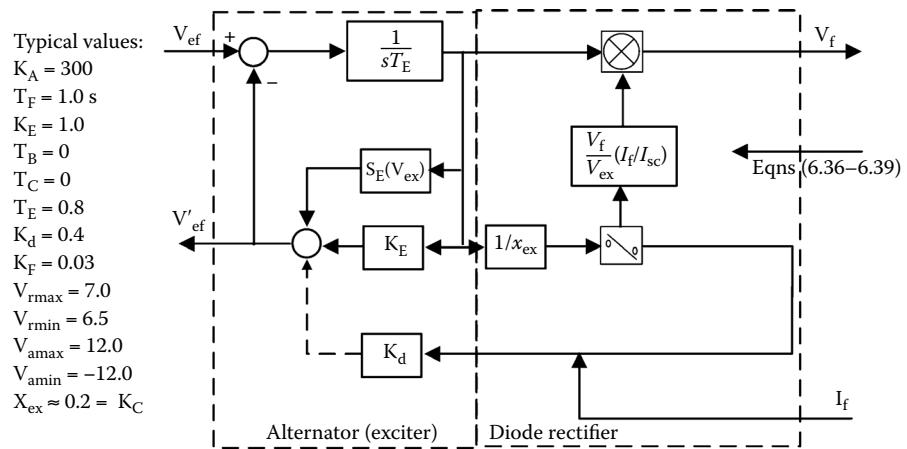
The basic AVR has to provide close-loop control of the SG terminal voltage by acting upon the exciter input with a voltage,  $V_{con}$ . It may have 1,2,3 stabilization loops and additional inputs, besides the reference voltage  $V_{ref}$  of SG and its measured value with load compensation  $V_c$ :

$$V_c = \left| V_g + (r_c + jX_c) I_g \right| \cdot \frac{1}{1 + sT_T} \quad (6.42)$$

The load compensator introduces the compensation of generator voltage variation due to load and also the delay  $T_T$  due to the voltage sensor. Other than that, a major field-winding voltage  $V_f$  loop is



(a)



(b)

FIGURE 6.34 (a) IEEE 1992 AC1A (brushless) excitation system and (b) AC exciter with diode rectifier.

introduced. The voltage regulator may be of many types (a lead–lag compensator, for example) with various limiters. Figure 6.34a and Figure 6.34b show the IEEE 1992 AC1A excitation system (with automatic voltage regulator).

A few remarks are in order:

- The feedback loop uses  $V_{ef}'$  instead of  $V_{ex}$  (exciter’s excitation voltage) or SG field-winding  $V_f$ .
- A windup limited single constant block with gain  $K_A$  is imposed to limit the output variable  $V_A$ .
- $V_{UEL}$  is the underexcitation limiter input.
- $V_{OEL}$  is the overexcitation limiter input.
- $(1 + sT_C)/(1 + sT_B)$  is the voltage regulator implemented as a simple lead–lag compensator.
- A non-windup limiter  $V_{rmax}, V_{rmin}$  is applied to the exciter excitation supply voltage.

The IEEE 1992 type ST1A excitation system model is shown in Figure 6.35. It represents a potential source-controlled rectifier. A transformer takes the power from the SG terminals and supplies the controlled rectifier. The exciter ceiling voltage is thus proportional to SG terminal voltage  $E_t$ . The rectifier

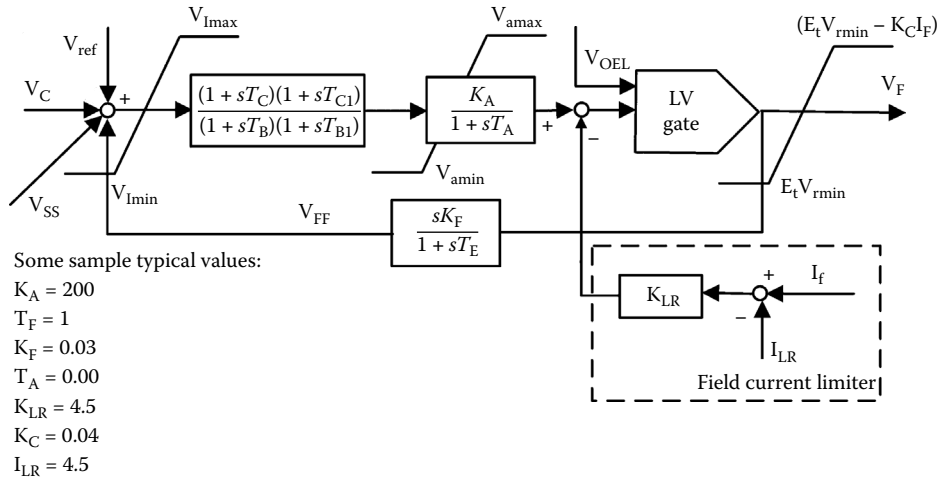


FIGURE 6.35 IEEE 1992 type ST1A excitation system (with automatic voltage regulator [AVR]).

and voltage regulation is represented by  $K_C$  ( $K_C = x_{ex}$  in previous structural diagrams). The field current  $I_F$  is limited through gain  $K_{LR}$  at the current limit  $I_{LR}$ . Again, non-windup and windup limiters are included, along with underexcitation ( $V_{UEL}$ ) and overexcitation ( $V_{OEL}$ ) limiters. The controlled rectifier model is considered only through the non-windup limiter  $V_{Rmax}$ ,  $V_{Rmin}$ .

The IEEE 451.2 standard from 1992 contains a myriad of models for existing excitation systems. More are added in Reference [4].

At the same time, more sophisticated and robust AVRs are presented, proposed, and tested. In what follows, a case study of a digital AVR design is presented.

Example 6.2: Digital Excitation System Design

Let us consider here a PID AVR to be used with a IEEE-1992 standard 421.5, type AC5A alternator and diode rectifier brushless exciter for turbine-SG sets of low to medium power (say up to 50 MW).

Provide a direct design method for the PID-type AVR.

Solution

The IEEE-1992, type AC5A analog excitation system model is modified to introduce the PID-type AVR (Figure 6.36).

The diode rectifier voltage regulation (reduction) with load is neglected here for simplicity.

Although the AVR is to be implemented digitally, the design of the PID controller may be done as if it were continuous, because the sampling frequency is more than 20 times the damped frequency of the closed-loop system.

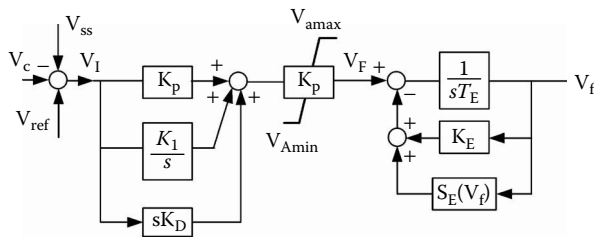


FIGURE 6.36 Simplified AC5A excitation system with PID-type automatic voltage regulator (AVR).

The transfer function of a PID controller is as follows:

$$G_C(s) = K_p + \frac{K_I}{s} + sK_D \quad (6.43)$$

where

$K_p$  = the proportional gain

$K_I$  = the integral gain

$K_D$  = the derivative gain

Selecting  $K_p$ ,  $K_I$ , and  $K_D$  is called controller tuning.

The AC exciter model in Figure 6.36 may be considered a first-order model, at least for small deviations (Figure 6.29). The SG may also be modeled as a first-order system represented by the excitation time constant  $T'_{d0}$  at constant speed, in the absence of the damper windings. So, the AC exciter plus the SG may be modeled through a second-order transfer function  $G(s)$ :

$$G(s) = \frac{l_{dm} / (r_f (S_E + K_E))}{(1 + sT'_{d0})(1 + sT_e)} \quad (6.44)$$

$$T_e = \frac{1}{(S_E + K_E)} \cdot T_E$$

$$T'_{d0} = (l_{dm} + l_{ff}) / (\omega_b r_f) \quad (6.45)$$

The closed-loop system characteristic is as follows:

$$G(s)G_C(s) + 1 = 0 \quad (6.46)$$

Consider, for simplicity,

$$l_{dm} / (r_f (S_E + K_E)) = 1$$

With Equation 6.43 and Equation 6.44, Equation 6.46 becomes

$$K_D^2 s^2 + K_p s + K_I = -(1 + sT'_{d0})(1 + sT_e)s \quad (6.47)$$

It is desirable that the closed-loop system be almost of second order. To do so, select a real negative pole  $s_3 = c$  in the far left-half of the plane with the other two as complex conjugates  $s_{1,2} = a \pm jb$ . The peak overshoot and settling time represent the basis for the pole placement (a,b,c). In this pole placement design method, from three equations, we find three unknowns:  $K_p$ ,  $K_I$ ,  $K_D$ . The controller settings of  $K_p$ ,  $K_I$ ,  $K_D$  give rise to two zeros that might be real or complex conjugates. The zeros affect the transient response; thus, some trial and error is required to complete the design. Over-designing the specifications, such as choosing a smaller than desired value to overshoot leads eventually to an adequate design.

For  $T'_{d0} = 1.5$  sec,  $T_e = 0.3$  sec,  $f_1 = 60$  Hz, settling time = 1.5 sec, peak overshoot = 10%, a good analog PID controller gain set is  $K_p = 39.33$ ,  $K_I = 76.50$ , and  $K_D = 5.4$  [7].

The conversion of PID analog settings into discrete form is straightforward with the trapezoidal integration method:

$$\begin{aligned} s &\Rightarrow \frac{(1-z^{-1})}{T}; \\ \frac{1}{s} &\Rightarrow \frac{T}{2} \frac{(1+z^{-1})}{1-z^{-1}} \end{aligned} \quad (6.48)$$

with  $z^{-1}$  representing the unit delay.

Consequently,  $G_C(z)$  is as follows:

$$G_C(z) = \left[ K_{PD} + \frac{K_{ID}}{1-z^{-1}} + K_{DD}(1-z^{-1}) \right] \cdot K_{AA} = \frac{\Delta V_F(z)}{\Delta V_I(z)} \quad (6.49)$$

with

$$\begin{aligned} K_{PD} &= K_p - K_I T / 2 \\ K_{ID} &= K_I T \\ K_{DD} &= K_D / T \end{aligned} \quad (6.50)$$

Again,  $K_{AA}$  was added in Equation 6.49. For the case in point,  $T = 12.5$  msec,  $K_{PD} = 777$ ,  $K_{ID} = 19$ ,  $K_{DD} = 8640$ , and  $S_E = 7$ , for a 75 kVA, 208 V, 0.8 PF lag generator [7].

Using the known property that  $Z^{-1}X(K) = X(K-1)$ , the expression of  $G_C(z)$  may be converted in time discrete form as follows:

$$\begin{aligned} \Delta F(K) &= \Delta F(K-1) + (K_{PD} + K_{ID} + K_{DD})\Delta V_I(K) - \\ &\quad - (K_{PD} + 2K_{DD})\Delta V_I(K-1) + K_{DD}\Delta V_I(K-2) \end{aligned} \quad (6.51)$$

where  $\Delta V_I$  is the generator voltage error (Figure 6.36).

A 50 kVAR reactive load application and rejection response is shown in Figure 6.37a, while a step change in voltage set point is presented in Figure 6.37b [7].

The settling time varies between 0.4 to 0.6 sec, while the voltage overshoot is below  $\pm 10\%$  (20 V) [7].

## 6.11 Underexcitation Voltage

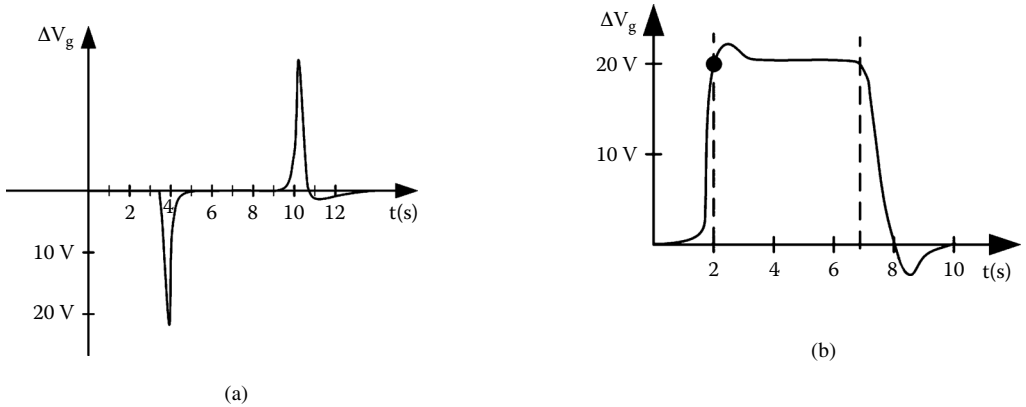
The input  $V_{UEL}$  in Figure 6.34a signals the presence of the UEL.

The UEL does not interfere with the AVR under normal transient or steady-state conditions, but takes over the AVR control under severe conditions. When the excitation level is too low, UEL boosts excitation, overriding or adding to the AVR.

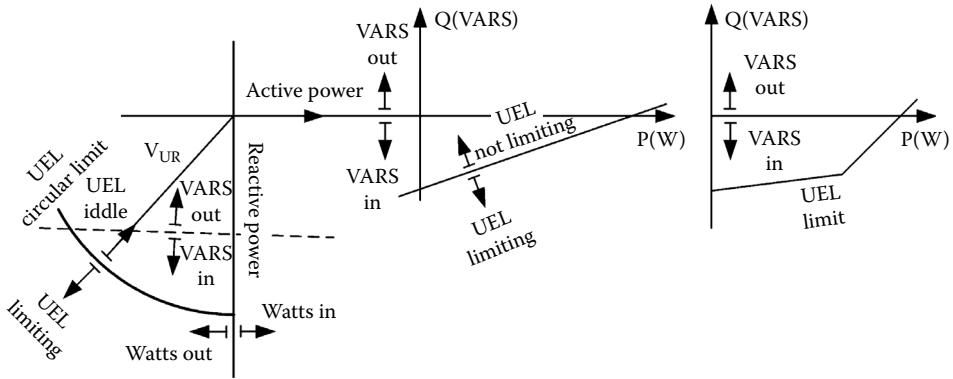
UEL acts to prevent loss of SG synchronism due to insufficient excitation or to prevent loading to overheating in the stator core end region of the SG, as defined in the leading reactive power zone of the SG capability curve (Chapter 4).

There are many causes for excitation reduction, such as the following:





**FIGURE 6.37** Generator voltage response: (a) 50 kVAR application and rejection and (b) step change in voltage set point.



**FIGURE 6.38** Underexcitation limiters: circular, straight line, and multisegment.

- Increases in the power system voltage may lead to reduction of SG excitation to keep the voltage at the SG terminals at a preset level by absorbing reactive power (underexcitation)
- Faults in the AVR
- Inadvertent reduction of AVR setting point  $V_{ref}$

When underexcited, the SG absorbs more reactive power, even when the active (turbine) power is maintained constant; thus, the machine stability limit in the  $P(\delta_v)$  curve (Chapter 4) is reached, or the SG stator core end region gets overheated.

The UEL may input the AVR either at the generator voltage setting point  $V_{ref}$  or after the lead-lag compensator (through a HV gate).

Three main types of UEL models were recommended by IEEE in 1995 (Figure 6.38) [8]:

- Circular type
- Straight-line type
- Multisegment type

A simple digital UEL is presented in Reference [9] and in Figure 6.39, where the limit reactive power from the  $P$ - $Q$  capability curves at various voltages is tabled as a function  $f(P, V_c)$ :

$$Q_{lim} = f(P, V_c) \quad (6.52)$$

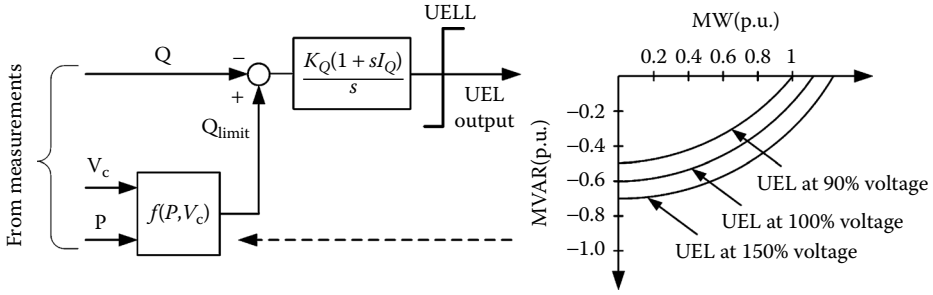


FIGURE 6.39 Simplified underexcitation limiter.

Care must be exercised to prevent UEL side effects on other limiters, such as loss of excitation (LOE) protection, PSSs, or the AVR, overexcitation limiter (OEL), volt/hertz limiters, and overvoltage limiters [10].

## 6.12 Power System Stabilizers (PSSs)

The field-winding current flux  $\Psi_f$  transients may be explored by using the third-order model ( $\Delta\Psi_f$ ,  $\Delta\omega_r$ ), where the damper cage is eliminated and so are the stator transients (Chapter 4).

After linearization [1],

$$\Delta T_e = K_1 \Delta\delta + K_2 \Delta\Psi_f \quad (6.53)$$

$$\Delta\Psi_f = \frac{K_3}{1 + sT_3} (\Delta V_f - K_4 \Delta\delta) \quad (6.54)$$

where

$\Delta T_e$  = the SG torque small deviation

$\Delta\delta$  = the power angle small deviation

$\Delta\Psi_f$  = the SG field-winding flux linkage small deviation

The change  $\Delta\Psi_f$  in field flux linkage (Equation 6.54), even for constant field-winding voltage  $V_f$  ( $\Delta V_f = 0$ ), is explained by armature reaction contribution change when the power angle changes ( $\Delta\delta \neq 0$ ).

Combining Equation 6.53 and Equation 6.54 yields the following:

$$\Delta T_e = K_1 \Delta\delta + \frac{K_3 K_2}{1 + sT_3} \Delta V_f - \frac{K_2 K_3 K_4}{1 + sT_3} \Delta\delta \quad (6.55)$$

The last term in Equation 6.55 represents the variation of  $\Psi_f$  transients caused by the electromagnetic torque, due to power angle variation. At steady state, or low oscillating frequency,

$$\Delta T_e \text{ due to } \Delta\Psi_f \text{ is } (-K_2 K_3 K_4 \Delta\delta); \omega \ll 1/T_3 \quad (6.56)$$

So, the field flux variation produces a negative synchronizing torque component (Equation 6.56). If

$$K_1 \leq K_2 K_3 K_4 \quad (6.57)$$

the system becomes monotonically unstable.

At higher oscillating frequencies ( $\omega \gg 1/T_3$ ) the last term of Equation 6.55 becomes

$$\Delta T_e = \frac{-K_2 K_3 K_4}{1 + j\omega T_3} \Delta \delta \approx \frac{K_2 K_3 K_4}{\omega T_3} (j\Delta \delta) \quad (6.58)$$

The airgap torque deviation caused by  $\Delta\Psi_f$  is now  $90^\circ$  ahead of power angle deviation and thus in phase with speed deviation  $\Delta\omega_r$ . Consequently, the field-winding flux linkage deviation  $\Delta\Psi_f$  produces a positive damping torque component. At 1 Hz,  $\Delta\Psi_f$  produces both a reduction in synchronizing torque and an increase in damping torque of the SG. Moreover, as  $K_2$  and  $K_3$  are positive, in general,  $K_4$  may be positive or negative [1]. With  $K_4 < 0$ , the synchronizing torque increase produced by  $\Delta\Psi_f$  is accompanied by a negative torque damping component. AVR's may introduce similar effects [1].

These two phenomena prompted the addition of PSSs as inputs to the AVR's. Damping the SG rotor oscillations is the main role of PSSs. The most obvious input of PSSs should be the speed deviation  $\Delta\omega_r$ .

By adding motion Equation 6.1 to Equation 6.43 and Equation 6.44, a simplified model for an AVR–PSS system can be derived, as shown in Figure 6.40. It is based on the small-signal third-order model of SG (Equation 6.43 through Equation 6.45), with the damper windings present only in the motion equation by the asynchronous (damping) torque  $K_D\Delta\omega_r$ .

The transfer function of the PSS would be a simple gain if the exciter and generator transfer function  $\Delta T_e/\Delta V_f$  was a pure gain. In reality, this is not so, and the  $G_{\text{PSS}}(s)$  has to contain some kind of phase compensation (phase lead) to produce a pure damping torque contribution. A simple such PSS transfer function is shown in Figure 6.41. The frequency range of interest is 1 to 2 Hz, in general. The washout component is a high-pass filter. Without washout contribution, steady-state changes in speed would modify the voltage  $V_s$  ( $T_w = 1$  to 20 sec). Especially fast response static exciters need PSS contribution to increase damping. A temporary increase of SG excitation current can significantly improve the transient stability, because the synchronizing power (torque) is increased.

The ceiling excitation voltage is limited to 2.5 to 3.0 P.U. in thermal power units. But, fast voltage variations lead to degraded damping as already pointed out. The PSS can improve damping if a terminal voltage limiter is added. This is true for the first positive rotor swing. But, after the first peak of the local swing, the excitation is allowed to decrease before the highest composite peak of the swing is passed by. Keeping excitation at the ceiling value would be useful until this composite swing peak is reached.

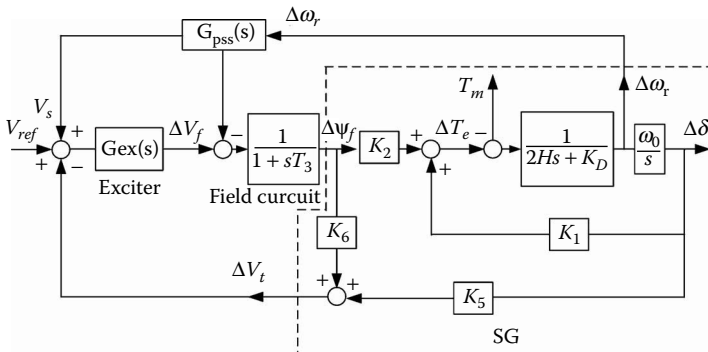


FIGURE 6.40 Automatic voltage regulator (AVR) with power system stabilizer (PSS): the small-signal model.

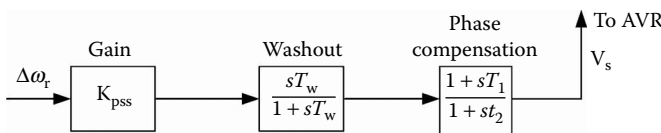


FIGURE 6.41 Basic power system stabilizer (PSS) transfer function.

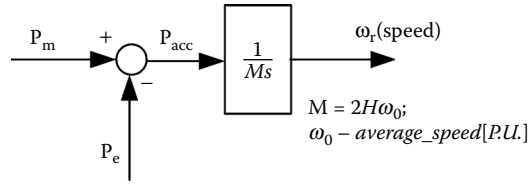


FIGURE 6.42 Accelerating power.

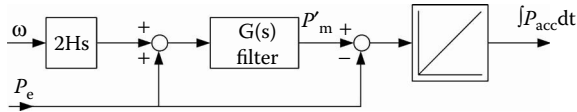


FIGURE 6.43 The integral of accelerating power as input to power system stabilizer (PSS).

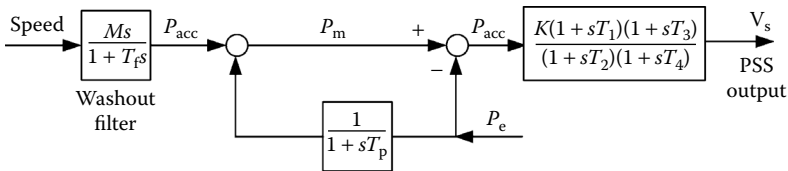


FIGURE 6.44 Accelerating power or speed input power system stabilizer (PSS).

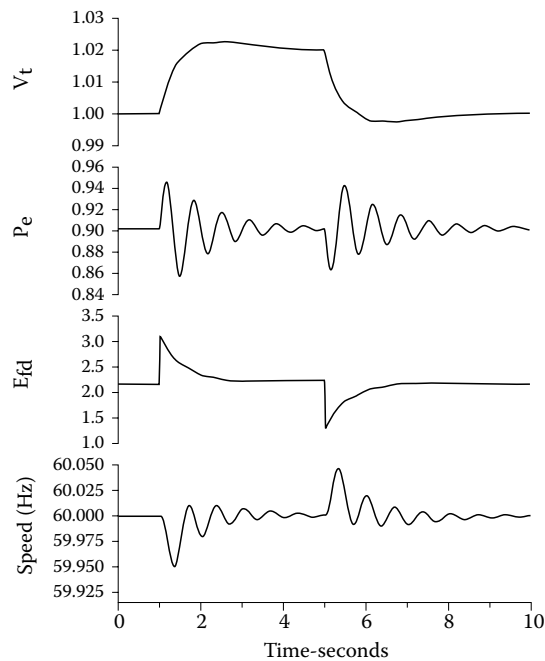
Discontinuous excitation control may be added to the PSS to keep the excitation voltage at its maximum over the entire positive swing of the rotor (around 2 sec or so). This is called transient stability excitation control (TSEC) and is applied, together or in place of other methods such as fast valving or generator tripping, in order to improve power system stability. TSEC imposes smaller duty requirements on the turbine shaft and on the steam supply of the unit.

As PSS should produce electromagnetic torque variations  $\Delta T_e$  in phase with speed, the measured speed is the obvious input to PSS. But what speed? It could be the turbine measured speed or the generator speed. Both of them are, however, affected by noise. Moreover, the torsional shaft dynamics cause noise that is very important and apparently difficult to filter out from the measured signal.

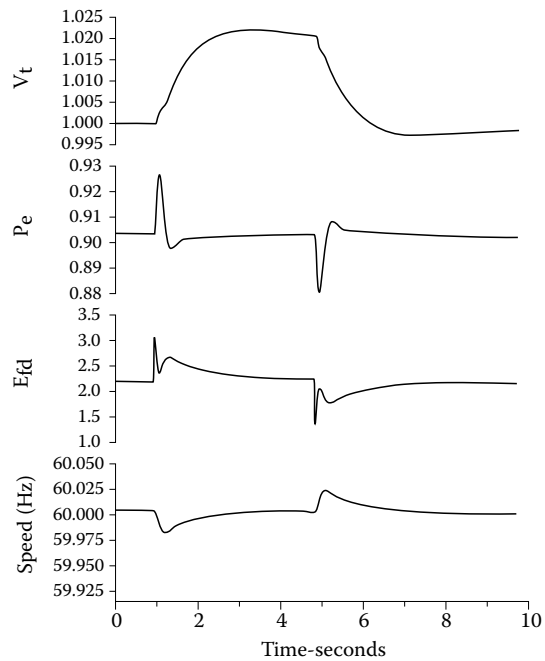
The search for other more adequate PSS inputs is based on the motion equation in power P.U. terms (Figure 6.3), redrawn here in slightly new denominations (Figure 6.42). It should be noticed that as  $P_m$  may not be measured, it could be estimated with  $\omega_r$  (estimated) and  $P_e$  (measured). It is practical to estimate  $\omega_r$  as the frequency of the generator voltage behind the transient reactance, as it varies slowly enough. This way, the speed sensor signal is not needed. Then, the structural diagram in Figure 6.42 can be manipulated to estimate the mechanical power  $P'_m$  and then calculate the accelerating power (Figure 6.43). With a single structure, both speed input and accelerating power input PSS may be investigated [11] (Figure 6.44).

The speed input of PSS may be obtained with  $T_p = 0$  and  $M = T_r$ . For  $T_p \neq 0$  and  $M = 2H$ , the accelerating power PSS is obtained. Accelerating power PSSs are claimed to perform better than speed PSSs in damping local system oscillations in the interval from 0.2 to 5 Hz for 220 MVA turbogenerators [11, 12]. Other inputs such as the electrical power variation,  $\Delta P_e$ , or frequency may be used with good results [13]. A great deal of attention has attracted the optimization of PSSs with solutions involving fuzzy logic [13, 14], linear optimal PSSs [15], synthesis [16], variable structure control [17], and  $H_\infty$  [18]. Typical effects of PSSs are shown in Figure 6.45a and Figure 6.45b [12].

The damping of electric power and speed (frequency) oscillations is evident. The excitation system design, including AVR and PSS, today in digital circuitry implementation is a complex enterprise that is beyond our scope here. For details, see the literature [1, 10–18].



(a)



(b)

**FIGURE 6.45** Simulation response to  $\pm 2\%$  step in terminal voltage: (a) no power system stabilizer (PSS) and (b) integral of accelerating power PSS.

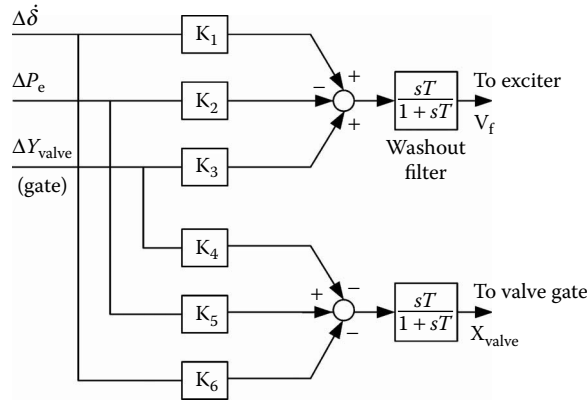


FIGURE 6.46 Primitive coordinated synchronous generator control system.

### 6.13 Coordinated AVR–PSS and Speed Governor Control

Coordinated voltage and speed control of SGs requires methods of multivariable nonlinear control design. Basically, the SG of interest may be modeled by a third-order model ( $\Delta\delta$ ,  $\Delta\omega$ , or  $\Delta\sigma$ ,  $\Delta\Psi_f$ ), while the power system to which it is connected might be modeled by a dynamic equivalent in order to produce a reduced-order system.

Optimization control methods are to be used to allocate proper weightings to various control variable participation. A primitive such coordinated voltage and speed SG control system is shown in Figure 6.46 [19]. The weights  $K_1$  to  $K_6$  are constants in Figure 6.46, but they may be adaptable. The washout filter also provides for zero steady-state error. A digital embodiment of coordinated exciter-speed-governor control intended for a low-head Kaplan hydroturbine generator is introduced in the literature [20,21].

Given the complexity of coordinated control of SG, continual online trained ANN control systems seem to be adequate [20–22] for the scope of this discussion. Coordinated control of SGs has a long way to go.

### 6.14 FACTS-Added Control of SG

FACTS stands for flexible AC transmission systems. FACTS contribute voltage and frequency control for enhancing power system stability. By doing so, FACTS intervene in active and reactive power flows in power systems, that is, between SGs and various loads supplied through transmission lines.

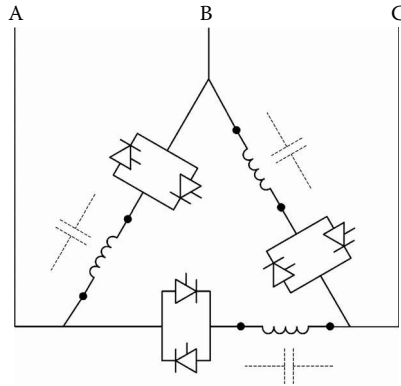
Traditionally, only voltage control was available through changing transformer taps or by switching current and adding fixed capacitors or inductors in parallel or in series.

Power electronics (PE) has changed the picture. In the early stages, PE has used back-to-back thyristors in series, which, line commutated, provided for high-voltage and power devices capable of changing the voltage amplitude. The thyristor turns off only when its current goes to zero. This is a great limitation.

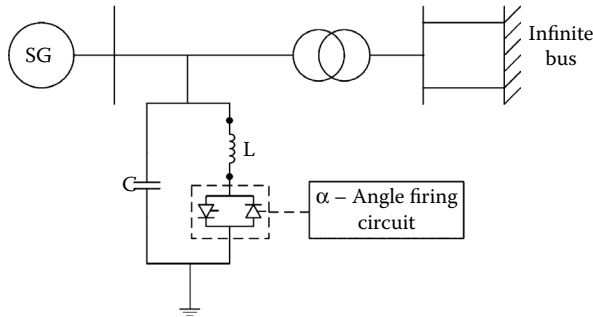
The GTO (gate turn-off thyristor) overcame this drawback. MCTs (MOS-controlled thyristor) or insulated-gate thyristors (IGCT) are today the power switches of preference due to a notably larger switching frequency (kHz) for large voltage and power per unit. For the megawatt range, IGBTs are used.

FACTS use power electronics to increase the active and reactive power transmitted over power lines, while maintaining stability. Integrated now in FACTS are the following:

- Static VAR compensators (SVCs)
- Static compensators (STATCOM)
- Thyristor-controlled resistors
- Power-electronics-controlled superconducting energy storage (SMES)



**FIGURE 6.47** Basic static VAR compensator (SVC).



**FIGURE 6.48** Synchronous generator with static VAR compensation.

- Series compensators and subsynchronous resonance (SSR) dampers
- Phase-angle regulators
- Unified power flow controller
- High-voltage DC (HVDC) transmission lines

SVCs deliver or drain controlled reactive power according to power system (mainly local) needs. SVCs use basic elements thyristor-controlled inductance or capacitor energy storage elements (Figure 6.47). Adequate control of voltage amplitude on reactor SVCs and capacitor SVCs, connected in parallel to the power system (in power substations), provides for positive or negative reactive power flow and contributes to voltage control.

The presence of SVCs at SG terminals or close to SG influences the reactive power control of the AVR–PSS system. So, a coordination between AVR–PSS and SVC is required [20, 21]. The SVC may enhance the  $P/Q$  capability at SG terminals [22] (Figure 6.48). A simplified structure of such a coordinated exciter SVC, based on multivariable control theory, is shown in Figure 6.49a and Figure 6.49b. It uses as variables the speed variation  $\delta$ , terminal voltage  $V_t$ , and active power  $P_e$  [23].

A standard solution is here considered in the form of a coordinated exciter–speed governor control system.

The improvement in dynamic stability boundaries is notable (Figure 6.49b) as claimed in Reference [23], with an optimal coordinated controller. STATCOM is an advanced SVC that uses a PWM converter to supply a fixed capacitor. GTOs or MCTs are used, and multilevel configurations are proposed. A step-down transformer is needed (Figure 6.50). The advanced SVC uses an advanced voltage source converter instead of a VARIAC. It is power electronics intensive but more compact and better in power quality.

$V_2$  may be brought in phase with  $V_1$  by adequate control. If  $V_2$  is made larger than  $V_1$  by larger PWM modulation indexing (more apparent capacitor), the advanced SVC acts as a capacitor at SG terminals.

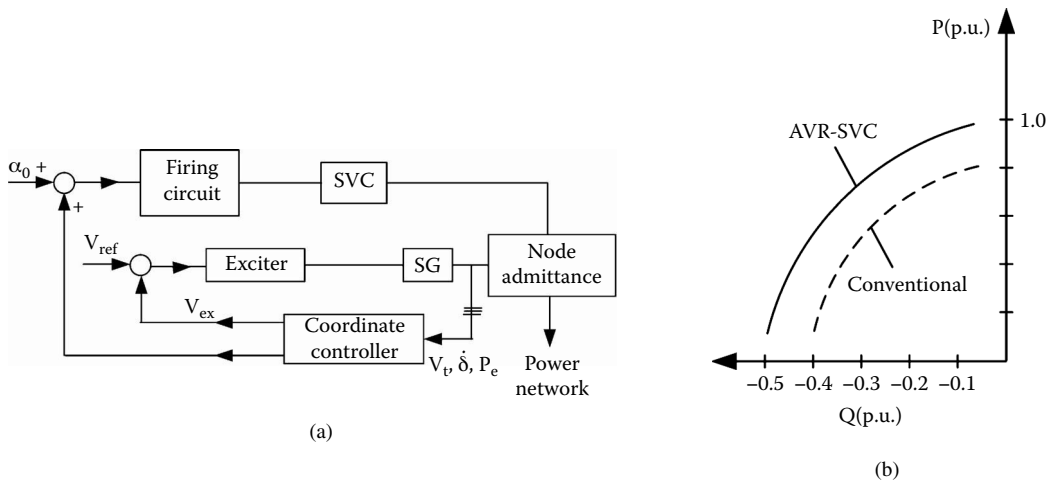


FIGURE 6.49 Coordinated exciter static voltage controller (SVC) control: (a) structural diagram and (b) dynamic stability boundary.

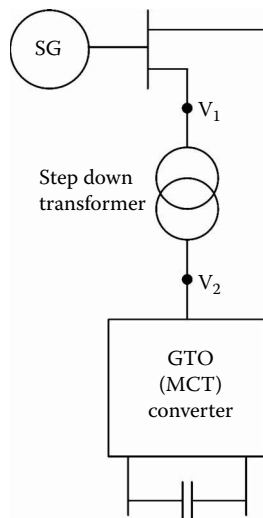


FIGURE 6.50 Advanced static voltage controller (SVC) = STATCOM.

If  $V_2 < V_1$ , it acts as an inductor. For a transformer reactance of 0.1 P.U., a  $\pm 10\%$  change in  $V_2$  may produce a  $\pm 100\%$  P.U. change in the reactive power flow from and to SVC. A parallel-connected thyristor-controlled resistor is used only for transient stability improvement, as it can absorb power from the generator during positive swings, preventing the loss of synchronism.

Note that with SVCs used as reactive power compensators and power factor controllers, the interference with the AVR-PSS controllers has to be carefully assessed, as adverse effects were reported by industry [24]. In essence, the SG voltage-supporting capability may be reduced.

Superconducting magnetic energy storage (SMES) may also be used for energy storage and for damping power system oscillations. The high-temperature superconductors seem to be a potential practical solution. They allow for current density in the superconducting coil wires of 100 A/mm<sup>2</sup>. Losses and volume per MWh stored are reduced, as is the cost.

SMES may be controlled to provide both active and reactive power control, with adequate power electronics. Four-quadrant  $P, Q$  operation is feasible (Figure 6.51), as demonstrated in the literature [25, 26].



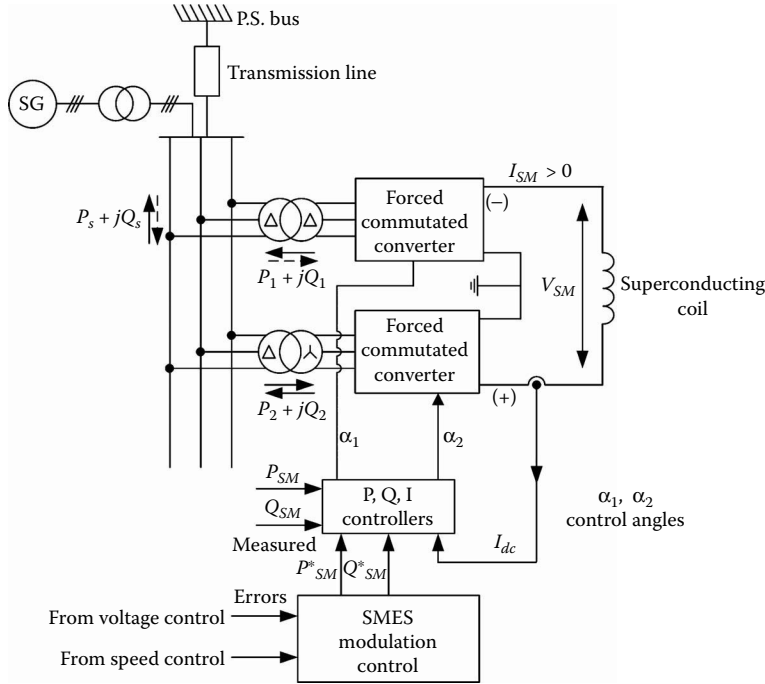


FIGURE 6.51 SMES with double-forced commutated converter for four-quadrant  $P, Q$  operation.

To investigate the action of SMES, let us consider a single SG connected to the power system (PS) bus by a transmission line. The dual converter impresses  $\pm V_{SM}$  volts on the superconducting coil. On the AC side of the converter, the phase angle between the voltage and current may vary from  $90^\circ$  when no energy is transferred from the power system to SMES, to  $0^\circ$  when the SMES is fully charging, and to  $180^\circ$  for maximum discharge of SMES energy into the power system.

The SMES current  $I_{SM}$  is not reversible, but the voltage  $V_{SM}$  is, and so is the converter output power  $P_{SM}$ :

$$\begin{aligned}
 P_{SM} &= I_{SM} V_{SM} \\
 V_{SM} &\approx K_M V_L \cos \alpha \\
 V_{SM} &\approx L_{ds} \cdot s \cdot I_{SM} \\
 P_{SM} &= K_M V_L I_{SM} \cos \alpha \\
 Q_{SM} &= K_M V_L I_{SM} \sin \alpha
 \end{aligned} \tag{6.59}$$

where

- $\alpha$  = the converter commutation angle
- $K_M$  = the modulation coefficient
- $V_L$  = the line AC voltage of the converter

For given  $P_{SM}^*$  and  $Q_{SM}^*$  demands, unique values of  $K_M$  and  $\alpha$  are obtained [27].

The DC voltage is controlled by changing the firing angle difference in the two converters:  $\alpha_{1,2}$ . The transfer function of the converter angle control loop may be written as follows:

$$\Delta V_{SM} = \frac{K_0}{1 + sT_\alpha} \Delta \alpha \tag{6.60}$$

The SMES energy stored is

$$W_{SM} = \frac{1}{2} L_d I_{SM0}^2 + \int_{t_0}^t P_{SM}(\tau) d\tau \quad (6.61)$$

The SMES power  $P_{SM}$  intervenes in the SG motion equations:

$$Ms\Delta\omega_r = \Delta P_m - D\Delta\omega_r - \Delta P_e - \Delta P_{SM}; \quad (6.62)$$

$$M = 2H$$

$$s\Delta\delta = \omega_b \cdot \Delta\omega_r \quad (6.63)$$

The power angle  $\delta$  is now considered as the angle between the no-load voltage of the SG and the voltage  $V_0$  of the PS bus. Essentially, the transmission line parameters  $r_T$  and  $x_T$  are added to SG stator parameters:  $D$  is the damping provided by load frequency dependence and by the SG damper winding;  $\Delta P_m$  is the turbine power variation;  $\Delta P_e$  is the electric power variation; and  $\Delta P_{SM}$  is the SMES power variation, all in P.U. at (around) base speed (frequency)  $\omega_b$ . The SMES may also influence the reactive power balance by the phase shift between converter AC voltages and currents.

It was shown that optimal multivariable control, with minimum time transition of the whole system from state A to B as the cost function, and  $|\Delta\alpha| < \pi/2$  as constraint, may produce speed and voltage stabilization for large PS active power load perturbations or faults (short-circuit) [28]. However, using speed variation  $\Delta\omega_r$  as input instead of optimal control to regulate the angle  $\Delta\alpha$  loop does not provide satisfactory results [28]. Notable SMES energy exchange within seconds is required for the scope [28].

Besides SG better control, the SMES was also proposed to assist automatic generation control, which deals with inter-area power exchange control [29]. This time, the input of the SMES is proportional to ACE (area control error, see Section 6.4) or is produced by a separate adaptive controller. In both cases, the superconducting inductor current deviation (derivative) is used as negative feedback in order to provide quick restoration of  $I_{SM}$  to the set point, following a change in the load demand [30, 31].

The SMES appears to be a very promising emerging technology, but new performance improvements and cost reductions are required before it will be common practice in power systems, together with other forms of energy storage, such as pump storage, batteries, fuel cells, and so forth.

### 6.14.1 Series Compensators

A transmission line may be modeled as lumped capacitors in series. The line impedance may be varied through thyristor-controlled series capacitors (Figure 6.52a and Figure 6.52b). The capacitor is varied by

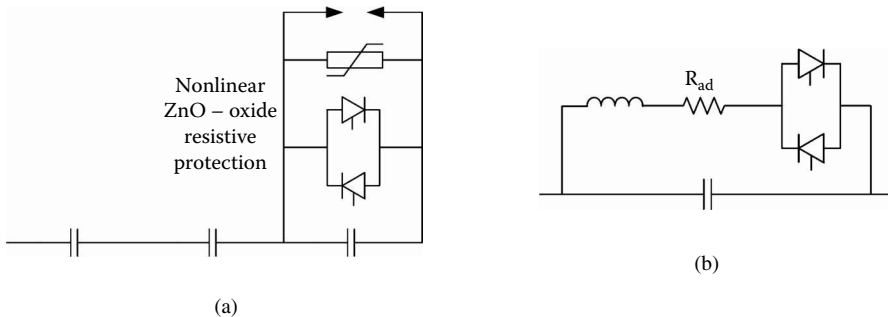


FIGURE 6.52 (a) Series compensator and (b) damper.

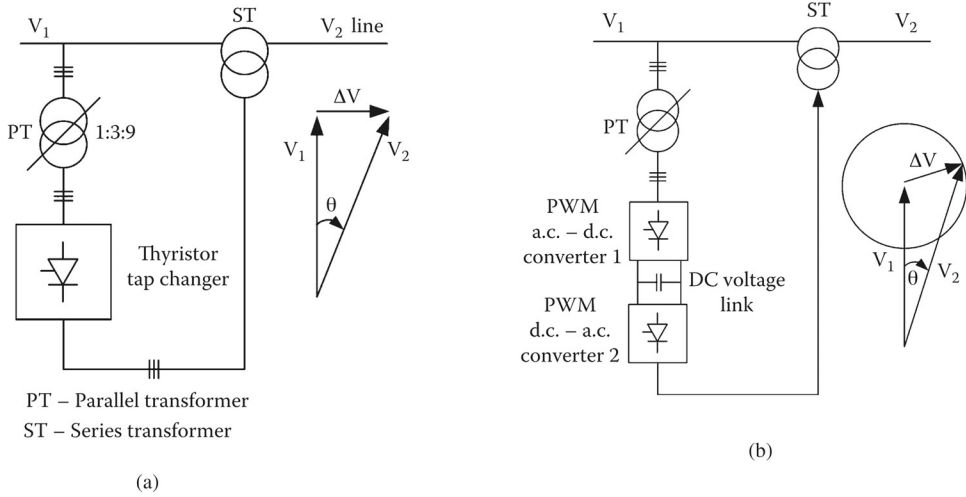


FIGURE 6.53 (a) Phase-angle regulator and (b) unified power flow controller.

PWM short-circuiting it through antiparallel thyristors. Overvoltage protection of thyristors is imperative. Nonlinear zinc-oxide resistors with a paralleled airgap is the standard protection for the scope.

When an additional resistance  $R_{ad}$  is added (Figure 6.52b), an oscillation damper is built. Series compensation of long heavily loaded transmission lines might produce oscillations that need attenuation.

### 6.14.2 Phase-Angle Regulation and Unified Power Flow Control

In-phase and quadrature voltage regulation done traditionally with tap changers in parallel-series transformers may be accomplished by power electronics means (FACTS; see Figure 6.53). The thyristor AC voltage tap changer (Figure 6.53a) performs the variation of  $\Delta V$  through the ST, while the unified power controller (Figure 6.53b) may vary both the amplitude and the phase of voltage variation  $\Delta V$ .

The phase-angle regulator may transmit reactive power to increase voltage  $V_2 > V_1$ , while the unified power flow controller allows for the flow of both active and reactive power, thus allowing for damping electromechanical oscillations.

High voltage direct current (HVDC) transmission systems contain a high-voltage high-power rectifier at the entry and a DC transmission line and an inverter at the end of it [1]. It is power electronics intensive, but it really makes the power transmission system much more flexible. It also interferes with other SG control systems.

As the power electronics SG control systems cost goes down, the few special (cable) or long power transmission lines HVDC, now in existence, will be extended in the near future, as they can do the following:

- Increase transmitted power capability of the transmission lines
- Produce additional electromechanical oscillation damping in the AC system
- Improve the transient stability
- Isolate system disturbances
- Perform frequency control of small isolated systems (by the output inverter)
- Interconnect between power systems of different frequencies (50 Hz or 60 Hz)
- Provide for active power and voltage dynamic support

## 6.15 Subsynchronous Oscillations

In Chapter 3, dedicated to prime movers, we mentioned the complexity of mechanical shaft, couplings, and mechanical gear in relation to wind turbine generators. In essence, the turbine-generator shaft system consists of several masses (inertias): turbine sections, generator rotor, mechanical couplings, and exciter

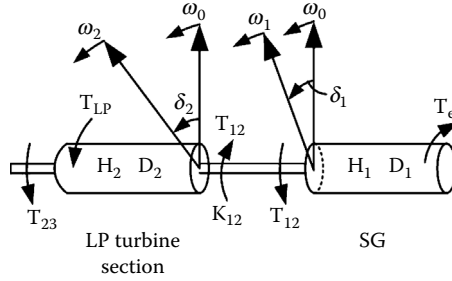


FIGURE 6.54 The two-mass shaft model.

rotor. These masses are connected by shafts of finite rigidity (flexibility). A mechanical perturbation will produce torsional oscillations between various sections of the shaft system that are above 5 to 6 Hz but, in general, below base frequency 50(60) Hz. Hence, the term “subsynchronous oscillations” is used.

The entire turbine-generator rotor oscillates with respect to other generators at a frequency in the range of 0.2 to 2 Hz.

Torsional oscillations may cause the following:

- Torsional interaction with various power system (or SG) controls
- Subsynchronous resonance in series (capacitor) compensated power transmission lines

Torsional characteristics of hydrogenerators units do not pose such severe problems, as the generator inertia is much larger than that in turbine-generator systems with shafts with total lengths up to 50 m.

### 6.15.1 The Multimass Shaft Model

The various gas or steam turbine sections, such as low pressure (LP), high pressure (HP), intermediate pressure (IP), generator rotor, couplings, and exciter rotor (if any), are elements of a lumped mass model.

Let us consider, for a start, only a two-mass rotor (Figure 6.54).

The motion equation of the generator and LP turbine rotors is as follows:

$$2H_1 \frac{d(\Delta\omega_1)}{dt} = K_{12}(\delta_2 - \delta_1) - T_e - D_1(\Delta\omega_1) \quad (6.64)$$

$$\frac{d\delta_1}{dt} = \Delta\omega_1 \cdot \omega_0$$

$$2H_2 \frac{d(\Delta\omega_2)}{dt} = T_{LP} + K_{23}(\delta_3 - \delta_2) - K_{12}(\delta_2 - \delta_1) - D_2(\Delta\omega_2) \quad (6.65)$$

$$\frac{d\delta_2}{dt} = \Delta\omega_2 \cdot \omega_0$$

$\omega_0$  is the rated electrical speed in rad/sec: 377 rad/sec for 60 Hz and 314 rad/sec for 50 Hz.

For more masses, more equations are added. For a coal-fired turbine generator with HP, IP, and LP sections (and static exciter), two more equations are added:

$$2H_3 \frac{d(\Delta\omega_3)}{dt} = T_{IP} + K_{34}(\delta_4 - \delta_3) - K_{23}(\delta_3 - \delta_2) - D_3(\Delta\omega_3) \quad (6.66)$$

$$\frac{d\delta_3}{dt} = \Delta\omega_3 \cdot \omega_0$$

$$\begin{aligned}
 2H_4 \frac{d(\Delta\omega_4)}{dt} &= T_{HP} - K_{34}(\delta_4 - \delta_3) - D_4(\Delta\omega_4) \\
 \frac{d\delta_4}{dt} &= \Delta\omega_4 \cdot \omega_0
 \end{aligned} \tag{6.67}$$

Two additional equations are needed for a nuclear power unit with LP<sub>1</sub>, LP<sub>2</sub>, IP, and HP sections with static exciter.

### Example 6.3

Consider a four-mass coal-fired steam turbine generator with HP, IP, and LP sections and a static exciter with inertias:  $H_1 = 0.946$  sec,  $H_2 = 3.68$  sec,  $H_3 = 0.337$  sec, and  $H_4 = 0.099$  sec.

The generator is at nominal power and 0.9 PF ( $T_e = 0.9$ ). The stiffness coefficients  $K_{12}$ ,  $K_{23}$ , and  $K_{34}$  are:  $K_{13} = 82.74$  P.U. torque/rad,  $K_{23} = 81.91$ , and  $K_{34} = 37.95$ .

Calculate the steady-state torque and angle of each shaft section if the division of powers is 30% for HP, 40% for IP, and 30% for LP.

#### Solution

Notice that the damping coefficients (due to blades and shafts materials, hysteresis, friction, etc.) are zero ( $D_1 = D_2 = D_3 = D_4 = 0$ ). The angle by which the LP turbine section leads the generator rotor is as follows (Equation 6.64):

$$\delta_2 - \delta_1 = T_{12} / K_{12}$$

But,  $T_{12} = T_e = 0.9$  (from power balance) and, thus,

$$\delta_2 - \delta_1 = 0.9 / 82.74 = 0.010877 \text{ rad(electrical)}$$

The torque between LP and IP shaft sections  $T_{23}$  at steady state is

$$T_{23} = T_{12} - T_{LP} = 0.9(1 - 0.3) = 0.54$$

From Equation 6.65,

$$\delta_3 - \delta_2 = T_{23} / K_{23} = 0.54 / 81.91 = 6.5926 \times 10^{-3} \text{ rad(electrical)}$$

Again,

$$T_{34} = T_{23} - T_{IP} = 0.54 - 0.4 \cdot 0.9 = 0.18$$

$$\delta_4 - \delta_3 = T_{34} / K_{34} = \frac{0.18}{37.95} = 4.7431 \times 10^{-3} \text{ rad(electrical)}$$

So, the HP turbine rotor section leads the generator rotor section by  $\delta_4 - \delta_1$ :

$$\begin{aligned}\delta_4 - \delta_1 &= 0.010877 + 6.5926 \times 10^{-3} + 4.7431 \times 10^{-3} \\ &= 2.22057 \times 10^{-2} \text{ rad} = 1.273 \text{ deg}\end{aligned}$$

at steady state.

### 6.15.2 Torsional Natural Frequency

The natural frequencies and modal shapes are to be obtained by finding the eigenvalues and vectors of the linearized free system equations from Equation 6.64 through Equation 6.67, with  $T_e = K_s \Delta \delta_i$ :

$$\Delta \dot{X} = A \Delta X \quad (6.68)$$

and  $\Delta T_{HP} = \Delta T_{LP} = \Delta T_{IP} = 0$ . With

$$\Delta X = \begin{bmatrix} \Delta \omega_1, \Delta \delta_1, \Delta \omega_2, \Delta \delta_2, \Delta \omega_3, \Delta \delta_3, \Delta \omega_4, \Delta \delta_4 \end{bmatrix}^T$$

|                   |     |                     |                                |                     |                                 |                     |                                   |                     |                        |
|-------------------|-----|---------------------|--------------------------------|---------------------|---------------------------------|---------------------|-----------------------------------|---------------------|------------------------|
|                   |     | $\Delta \omega_1$   | $\Delta \delta_1$              | $\Delta \omega_2$   | $\Delta \delta_2$               | $\Delta \omega_3$   | $\Delta \delta_3$                 | $\Delta \omega_4$   | $\Delta \delta_4$      |
|                   | $ $ | $-$                 | $-$                            | $-$                 | $-$                             | $-$                 | $-$                               | $-$                 | $-$                    |
| $\Delta \omega_1$ | $ $ | $-\frac{D_1}{2H_1}$ | $-\frac{(K_{12} + K_s)}{2H_1}$ |                     | $\frac{K_{12}}{2H_1}$           |                     |                                   |                     |                        |
| $\Delta \delta_1$ | $ $ | $\omega_0$          |                                |                     |                                 |                     |                                   |                     |                        |
| $\Delta \omega_2$ | $ $ |                     | $\frac{K_{12}}{2H_2}$          | $-\frac{D_2}{2H_2}$ | $-\frac{K_{12} + K_{23}}{2H_2}$ |                     | $\frac{K_{23}}{2H_2}$             |                     |                        |
| $\Delta \delta_2$ | $ $ |                     |                                | $\omega_0$          |                                 |                     |                                   |                     |                        |
| $\Delta \omega_3$ | $ $ |                     |                                |                     | $\frac{K_{23}}{2H_3}$           | $-\frac{D_3}{2H_3}$ | $-\frac{(K_{23} + K_{34})}{2H_3}$ |                     | $\frac{K_{34}}{2H_3}$  |
| $\Delta \delta_3$ | $ $ |                     |                                |                     |                                 | $\omega_0$          |                                   |                     |                        |
| $\Delta \omega_4$ | $ $ |                     |                                |                     |                                 |                     | $\frac{K_{34}}{2H_4}$             | $-\frac{D_4}{2H_4}$ | $-\frac{K_{34}}{2H_4}$ |
| $\Delta \delta_4$ | $ $ |                     |                                |                     |                                 |                     |                                   | $\omega_0$          |                        |

The natural frequencies are the eigenvalues of  $|A|$ :

$$|A| - \lambda |I| = 0 \quad (6.69)$$

With zero damping coefficients ( $D_i = 0$ ), the eigenvalues are complex numbers  $j\omega_i$  ( $i = 0, 1, 2, 3$ ). The corresponding frequencies for the case in point are 22.4 Hz, 29.6 Hz, and 52.7 Hz. The first, low (system mode) frequency is not included here, as it is the oscillation of the entire rotor against the power system:

$$f_s = \frac{\omega_s}{2\pi} = \frac{\omega_0}{2\pi} \sqrt{\frac{K_s}{2(H_1 + H_2 + H_3 + H_4)}}$$

With  $K_s = 1.6$  P.U. torque/rad,

$$f_s = 60 \times \sqrt{\frac{1.6}{2(0.946 + 3.68 + 0.33 + 0.049) \times 377}} = 1.23 \text{ Hz}$$

The torsional free frequencies are, in general, above 6 to 8 Hz, so they do not interfere, in this case, with the excitation, speed-governor, or inter-tie control (below 3 to 5 Hz).

The PSS may interfere with the high (above 8 Hz) torsional frequencies, as it is designed to provide pure damping (zero phase shift at system frequency  $f_s = 1.23$  Hz in our case). At 22.4 Hz, PSS may produce a large phase lag (well above  $20^\circ$ ) and notable negative damping, hence, instability.

To eliminate such a problem, the speed sensor should be placed between LP and IP sections to reduce the torsional mode influence on speed feedback. Another possibility would be a filter with a notch at 22.4 Hz. The terminal voltage limiter may also produce torsional instability. Adequate filter is required here also.

HVDC systems may, in turn, cause torsional instabilities. But, it is the series capacitor compensation of power transmission lines that most probably interacts with the torsional dynamics.

## 6.16 Subsynchronous Resonance

In a typical (noncompensated) transmission system, transients (or faults) produce DC attenuated 60 (50) Hz and 120 (100) Hz torque components (the latter, for unbalanced loads and faults). Consequently, the torsional frequencies always originate from these two frequencies.

Series compensation is used to bring long power line capacity closer to the thermal rating. In essence, the transmission line total reactance is partially compensated by series capacitors. Consider a simple radial system (Figure 6.55).

The presence of the capacitor eliminates the DC stator current transients, but it introduces offset AC currents at natural frequency of the inductance capacitance (LC) series circuits:

$$\omega_n \approx \frac{1}{\sqrt{LC}} = \omega_0 \sqrt{\frac{X_C}{X_L}} \quad (6.70)$$

with

$$X_L \approx (X'' + X_T + X_E) \omega_0; X_C = 1 / \omega_0 C \quad (6.71)$$

$X'' = (X_d'' + X_q'')/2$  is the subtransient reactance of the SG. The  $f_n$  frequency offset stator currents produce rotor currents at slip frequency:  $60 (50) - f_n$ . The subsynchronous resonance frequency  $f_n$  may depend solely on the degree of compensation  $X_C/X_L$  (Table 6.1).

Shunt compensation (SVC) tends to produce oversynchronous natural frequencies unless the degree of SVC is high and the transmission line is long. There are two situations when series compensation may cause undamped subsynchronous oscillations:

- Self-excitation due to induction generator effect
- Interaction with torsional oscillations

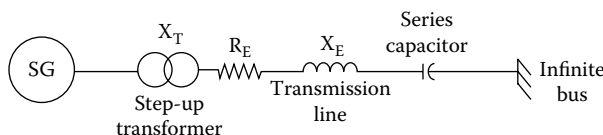


FIGURE 6.55 Radial system with series capacitor compensation.

**TABLE 6.1** Subsynchronous Resonance Frequency

| Compensation Ratio in<br>% ( $X_C/X_L$ ) | Natural Frequency<br>$f_n$ (Hz) | Slip Frequency<br>$60-f_n$ (Hz) |
|------------------------------------------|---------------------------------|---------------------------------|
| <b>10</b>                                | 18                              | 42                              |
| <b>20</b>                                | 26.83                           | 33.17                           |
| <b>30</b>                                | 32.86                           | 27.14                           |
| <b>40</b>                                | 37.94                           | 22.06                           |
| <b>50</b>                                | 42.46                           | 17.54                           |

As  $f_n < f_0$ , the slip  $S$  in the SG is negative. Consequently, with respect to stator currents at frequency  $f_n$ , the SG behaves like an induction generator connected to the power system.

The effective synchronous resistance of the SG at  $S = (f_n - f_0)/f_0 < 0$ ,  $R_{as}$ , is negative. As such, it may surpass the positive resistance of the transmission line. The latter becomes an LC circuit with negative resistance. Electrical oscillations will self-excite at large levels. A strong damper winding in the SG or an additional resistance in the power line would solve the problem. The phenomenon is independent of torsional dynamics, being purely electromechanical.

If the series compensation slip frequency  $60(50)$  Hz  $-f_n$  is close to one of the torsional-free frequencies of the turbine-generator unit, torsional oscillations are initiated. This is the subsynchronous resonance (SSR). Torsional oscillations buildup may cause shaft fatigue or turbine-generator shaft breaking. In fact, the SSR was “discovered” after two such disastrous events took place in 1970 to 1971.

Some countermeasures to SSR are as follows:

- Damping circuits in parallel with the series compensation capacitors (Figure 6.52b)
- Dynamic filters: the unified power flow controller may be considered for the scope (Figure 6.53b), as it can provide an additional voltage  $\Delta V$  of such a phase as to compensate the SSR voltage [32]
- Thyristor-controlled shunt reactors or capacitors (SVCs)
- Selected frequency damping in the exciter control [33]
- Superconducting magnetic storage systems: the ability of the SMES to quickly inject or extract from the system active or reactive power by request makes it a very strong candidate to SSR attenuation (about 1 sec attenuation time is claimed in Reference [34])
- Protective relays that trip the unit when SSR is detected in speed by generator current feedback sensors

## 6.17 Summary

- Control of SGs means basically active power (or speed) and reactive power (or voltage) control.
- Active power (or speed) control of SGs is performed through turbine close-loop speed governing.
- Reactive power (or voltage) control is done through field-winding voltage (current  $I_f$ ) close-loop control (AVR).
- Though, in principle, weakly coupled, the two controls interact with each other. The main decoupling means used so far is the so-called power system stabilizer (PSS). The PSS input is active power (or speed) deviation. Its output enters the AVR control system with the purpose of increasing the damping torque component.
- When the SG operates in connection with a power system, two more control levels are required besides primary control (speed governing and AVR–PSS). They are automatic generation control (AGC) and economic dispatch with security assessment generation allocation control.
- AGC refers to frequency-load control and inter-tie control.
- Frequency-load control means to allocate frequency (speed)/power characteristics for each SG and move them up and down through area control error (ACE) to determine how much power contribution is asked from each SG.



- ACE is formed by frequency error multiplied by a frequency bias factor  $\lambda_r$  added to inter-tie power error  $\Delta P_{tie}$ . ACE is then PI controlled to produce load-frequency set points for each SG by allocating pertinent participation factors  $\alpha_i$  (some of them may be zero).
- The amount of inter-tie power exchange between different areas of a power system and the participation factors of all SGs are determined in the control computer by the economic dispatch with security assessment, based on lowest operation costs per kilowatt-hour or on other cost functions.
- Primary (speed and voltage) control is the fastest (seconds), while economic dispatch is the slowest (minutes).
- Active and reactive power flow in a power system may be augmented by flexible AC transmission systems (FACTS) that make use of power electronics and of various energy storage elements.
- Primary (speed and voltage) control is slow enough that third- and fourth-order simplified SG models suffice for its investigation.
- Constant speed (frequency) closed loop is feasible only in isolated SGs.
- SGs operating in a power system have speed-droop controllers to allow for power sharing between various units.
- Speed droop is typically 4 to 5%.
- Speed governors require at least second-order models, while for hydraulic turbines, transient speed-droop compensation is required to compensate for the water starting time effect. Speed governors for hydraulic turbines are the slowest in response (up to 20 sec and more for settling time), while steam turbines are faster (especially in fast valving mode), but they show an oscillatory response (settling time is generally less than 10 sec).
- In an isolated power system with a few SGs, automatic generation control means, in fact, adding an integrator to the load-frequency set point of the frequency/power control to keep the frequency constant for that generator.
- AGC in interconnected power systems means introducing the inter-tie power exchange error  $\Delta P_{tie}$  with frequency error weighted by the frequency bias factor to form the area control error (ACE). ACE contains PI filters to produce  $\Delta P_{ref}$  that provides the set point level of various generators in each area. Consequently, not only the frequency is controlled but also the inter-tie power exchange, all according to, say, minimum operation costs with security assessment.
- The time response of SG in speed and power angle for various power perturbations is qualitatively divided into four stages: rotor swings, frequency drops, primary control (speed and voltage control), and secondary control (inter-tie control and economic dispatch). The frequency band of speed-governor control in power systems is generally less than 2 Hz.
- Spinning reserve is defined as rated power of all SGs in a system minus the actual power needed in certain conditions.
- If spinning reserve is not large enough, frequency does not recover; it keeps decreasing. To avoid frequency collapse, load is shedded in designated substations in one to three stages until frequency recovers. Underfrequency relays trigger load shedding in substations.
- Active and reactive powers of various loads depend on voltage and frequency to a larger or smaller degree.
- Equilibrium of frequency (speed) is reached for active power balance between offer (SG) and demand (loads).
- Similarly, equilibrium in voltage is reached for balance in reactive power between offer and demand. Again, if not enough reactive power reserve exists, voltage collapse takes place. To avoid voltage collapse, either important reactive loads are shedded or additional reactive power injection from energy storage elements (capacitors) is performed.
- The SG contribution to reactive power (voltage) control is paramount.
- Voltage control at SG terminal AVR is done through field-winding (excitation) voltage  $V_f$  (current  $I_f$ ) control. The frequency band of automatic voltage regulators (AVR) is within 2 to 3 Hz, in general.

- The DC excitation power for SGs is provided by exciters.
- Exciters may be of three main types: DC exciters, AC exciters, and static exciters.
- DC exciters contain two DC commutator generators mounted on the SG shaft: the auxiliary exciter (AE) and the main exciter (ME). The ME armature supplies the SG excitation through brushes and slip-rings at a full excitation power rating. The AE armature excites the ME. The AE excitation is power electronics controlled at the command (output) of AVR. DC exciters are in existence for SGs up to 100 MW, despite their slow response — due to large time constants of AE and ME — and commutator wear — due to the low control power of AE.
- AC exciters contain an inside-out synchronous generator (ME) with output that is diode-rectified and connected to the SG excitation winding. It is a brushless system, as the ME DC excitation circuit is placed on the stator and is controlled by power electronics at the command (output) of AVR. With only one machine on the SG shaft, the brushless AC exciter is more rugged and almost maintenance free. The control power is 1/20 (1/30) of the SG excitation power rating, but the control is faster, as now only one machine (ME) time constant delay exists.
- Static exciters are placed away from the SG and are connected to the excitation winding of SG through brushes and slip-rings. They are power electronics (static) AC–DC converters with very fast response. Controlled rectifiers are typical, but diode rectifiers with capacitor filters and four-quadrant choppers are also feasible. Static exciters are the way of the future now that slip-ring–brush energy transmission at 30 MW was demonstrated in 400 MVA doubly fed induction generator pump-storage power plants. Also, converters up to this rating are already feasible.
- Exciter modeling requires, for AVR design, a new, nonreciprocal, P.U. system where the base excitation voltage is that which produces no load rated voltage at SG terminals at no load. The corresponding P.U. field current is also unity in this case:

$$I_{fb} = I_{dm} I_f = 1; V_f = I_f r_f$$

$$V_{fb} = \frac{I_{dm}}{r_f} V_f = 1$$

This way, working with P.U. voltages in the range of  $10^{-3}$  is avoided.

- The simplest model of SG excitation is a first-order delay with the transient open-circuit time constant:

$$T'_{d0} = \frac{(I_{dm} + I_{ff})}{r_f} \cdot \frac{1}{\omega_0} \quad (\text{seconds})$$

and a unity P.U. gain (Equation 6.22).

- The DC exciter model (one level; ME or AE), accounting for magnetic saturation, is a nonlinear model that contains a first-order delay and a nonlinear saturation-driven feedback. For small-signal analysis, a first-order model with saturation-variable gain and a time constant is obtained.
- For the AC exciter, the same model may be adopted but with one more feedback proportional to field SG current, to account for a  $d$ -axis demagnetizing armature reaction in the ME (alternator).
- The diode rectifier may be represented by its steady-state voltage/current output characteristics. Three diode commutation modes are present from no load to short-circuit. In essence, the diode rectifier characteristic shows a voltage regulation dependent on ME commutation (subtransient) inductance.
- The controlled rectifier may also be modeled by its steady-state voltage/current characteristic with the delay angle  $\alpha$  as parameter and control variable.
- The basic AVR acts upon the exciter input and may have one to three stabilizing loops and, eventually, additional inputs. The sensed voltage is corrected by a load compensator.

- A lead–lag compensator constitutes the typical AVR stabilizing loop.
- Various exciters and AVRs are classified in IEEE standard 512.2 of 1992.
- Alternative AVR stabilizer loops such as PID are also practical.
- All AVR systems are provided with underexcitation (UEL) and overexcitation (OEL) limiters.
- Exciter dynamics and AVRs may introduce negative damping generator torques. To counteract such a secondary effect, power system stabilizers (PSSs) were introduced.
- PSSs have speed deviation or accelerating power deviation as input and act as an additional input to AVR.
- The basic PSS contains a gain, a washout (high-pass) filter, and a phase compensator in order to produce torque in phase with speed deviation (positive damping). The role of the washout filter is to avoid PSS output voltage modification due to steady-state changes in speed.
- Accelerating-power-integral input PSSs were proven better than speed or frequency or electric power deviation input PSSs.
- Besides independent speed-governing and AVR–PSS control of SGs, coordinated speed and voltage SG control were introduced through multivariable optimal control methods.
- Advanced nonlinear digital control methods, such as fuzzy logic, ANN,  $\mu$  synthesis,  $H_\infty$ , and sliding-mode, were proposed for integrated SG generator control.
- Power-electronics-driven active/reactive power flow in power systems may be defined as FACTS (flexible AC transmission systems). FACTS may make use of external energy storage elements such as capacitors, resistors, and inductors (normal or of superconductors material). They also assist in voltage support and regulation.
- FACTS may enhance the dynamic stability limits of SGs but interfere with their speed governing and AVR.
- The steam (or gas) turbines have long multimass shafts of finite rigidity. Their characterization by lumped 4,5 masses is typical.
- Such flexible shaft systems are characterized by torsional natural frequencies above 6 to 8 Hz, in general, for large turbine generators.
- Series compensation by capacitors to increase the transport capacity of long power lines leads to the occurrence of offset AC currents at natural frequency  $f_n$  solely dependent on the degree of transmission-line reactance compensation by series capacitors ( $X_C/X_L < 0.5$ ).
- It is the difference  $f_0 - f_n$ , the slip (rotor) frequency of rotor currents due to this phenomenon that may fall over a torsional free frequency to cause subsynchronous resonance (SSR).
- Subsynchronous resonance may cause shafts to break or, at least, cause their premature wearing.
- The slip frequency currents of frequency  $f_0 - f_n$  produced by the series compensation effect, manifest themselves as if the SG were an induction generator connected at the power grid. As slip is negative ( $f_n < f_0$ ), an equivalent negative resistance is seen by the power grid. This negative resistance may overcompensate for the transmission line resistance. With negative overall resistance, the transmission-line reactance plus series compensation capacitor circuit may ignite dangerous torque pulsations. This phenomenon is called induction generator self-excitation and has to be avoided. A way to do it is to use a strong (low resistance) damper cage in SGs.
- Various measures to counteract SSR were proposed. Included among them are the following: damping circuit in parallel with the series capacitor, thyristor-controlled shunt reactors or capacitors, selected frequency damping in AVR, superconducting magnetic energy storage, and protective relays to trip the unit when SSR is detected through generator speed or by current feedback sensors oscillations.
- Coordinated digital control of both active and reactive power with various limiters, by multivariable optimal theory methods with self-learning algorithms, seems to be the way of the future, and much progress in this direction is expected in the near future.
- Emerging silicon-carbide power devices [34] may enable revolutionary changes in high-voltage static power converters for frequency and voltage control in power systems.

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